BEFORE THE PUBLIC UTILITIES COMMISSION OF

THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate And Refine Procurement Policies and Consider Long Term Procurement Plans	Rulemaking 12-03-014 (Filed March 22, 2012)

PREPARED TESTIMONY OF KEVIN WOODRUFF ON BEHALF OF THE UTILITY REFORM NETWORK REGARDING TRACK 4 – SONGS RETIREMENT

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September 30, 2013

INTRODUCTION

Q. Please introduce yourself.

A. I am Kevin Woodruff. I am the Principal of the consulting firm of Woodruff Expert Services. I have testified before this Commission on many occasions regarding electric utility resource planning and procurement and project valuation issues. My resume is appended hereto as Attachment 1.

Q. On whose behalf are you testifying?

A. I am providing this testimony on behalf of The Utility Reform Network (TURN), an organization that has long represented the interests of smaller consumers before this Commission.

Q. What other parties' testimony and issues do you address in this testimony?

A. I address the testimony the California Independent System Operator (CAISO) served in Track 4 of this docket on August 5, 2013 and the Track 4 testimony the Southern California Edison Company (SCE) and the San Diego Gas & Electric Company (SDG&E) served on August 26, 2013.[1,2] All these testimonies provided estimates of the amount of generating capacity needed to maintain reliable electric service in the western Los Angeles Basin (LA Basin) portion of SCE's service territory and in SDG&E's entire service territory given the retirement of the San Onofre Nuclear Generating Station (SONGS) and the anticipated retirements of gas-fired generators (GFGs) in the region that rely on Once Through Cooling (OTC) technology.[3] SCE and SDG&E also submitted analyses of other means for meeting such needs, specifically new transmission projects

[1] I refer to these documents as the *CAISO Track 4 Testimony*, *SCE Track 4 Testimony* and *SDG&E Track 4 Testimony*. When referencing SDG&E's testimony, I also add the last name of the specific witness, either Robert Anderson or John Jontry.

[2] For simplicity, I will at times refer to SCE and SDG&E collectively as "the utilities" or "the IOUs". Unless otherwise noted, these terms are not meant to refer to any other utility.

[3] I also refer to these areas as the LA Basin and San Diego Local Reliability Areas (LRAs), respectively.

and additional "preferred resources."[4] Each utility also asked the Commission for authority to solicit 500 MW of new resources, to be chosen on an "all source" basis from among gas-fired and preferred resources, to meet local needs.

I also briefly address an issue raised by the testimony the City of Redondo Beach (Redondo Beach) served in this docket on August 26, 2013

SUMMARY AND RECOMMENDATIONS

Q. What are the major issues you address in this testimony?

A. I address two major issues. I first make the point that solving local capacity problems in the state's South Coast will not be a quick or simple process.[5] There are no single "silver bullet" projects, technologies or other solutions that will cure all the South Coast's reliability challenges in one "fell swoop." Nor can anyone now identify a "grand plan" composed of a set of now-known projects that can safely be assumed to be implemented and collectively address the area's reliability needs. Instead, the Commission, the state's other energy leaders, market participants and other stakeholders will need to focus for a number of years on identifying and implementing a multiplicity of projects or programs that will together meet such needs.

Second, I address the CAISO's use of an especially conservative approach in its modeling that could impose significant additional costs on electricity customers for questionable increases in reliability. The CAISO is not required by national or regional planning standards to use this particular assumption, which is the prohibition on the use of controlled "load shedding" to address the key "N-1-1" contingency that drives local need in both the LA Basin and San Diego, which is the overlapping outage of SDG&E's

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4 For purposes of this testimony only, I include storage when I refer to preferred resources.

5 I use the phrase "South Coast" herein to refer jointly to the LA Basin and San Diego LRAs.

Sunrise Powerlink (Sunrise) and Southwest Powerlink (SWPL) transmission lines.[6] Rather, the CAISO's decision to not consider "load shedding" as a means of mitigating that contingency is entirely discretionary.

Q. Based on your analysis of these issues, what actions to you recommend the Commission take in this portion of this Track, that is, before the CAISO files the results of its *2013-2014 Transmission Plan* early next year?

A. As to the first matter, I recommend the Commission authorize both SCE and SDG&E to solicit an additional 500 MW each of local resources on an "all source" basis, that is, from among all technologies that can meet or reduce need within the LA Basin and San Diego Local Reliability Areas (LRAs). More generally, I recommend the Commission anticipate reviewing and – if appropriate – authorizing a number of projects designed to meet the utilities' local needs over the next few years and act on those proposals without any delay beyond that required by due process. I also recommend the utilities pursue the other alternatives they discussed in their testimonies and submit them for Commission review.[7]

As to the second issue, I recommend that at least for the time being, the Commission adopt procurement recommendations in this docket based on the less conservative approach that permits load shedding to mitigate the key "N-1-1" contingency identified above, rather than the CAISO's more conservative and costly method. Should the state's leaders decide that customers should bear the additional cost the CAISO's approach would impose, the Commission can make the corollary higher and more costly need findings in later dockets.

I discuss these matters in more detail in the following two sections of this testimony.

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[6] *CAISO Track 4 Testimony*, 18:17-21. I variously refer below to this contingency as the key or critical "N-1-1" contingency or the "Sunrise / SWPL Outage" contingency.

[7] See *SCE Track 4 Testimony* at 49:1-54:11 (regarding the Living Pilot) and 61:15-62:10 (regarding the Contingent Site Development Plan) and SDG&E *Track 4 Testimony, Anderson*, 5:6-15 and 18:15-19:10 (regarding the Energy Park).

Q. Are there any other issues you address in this testimony?

A. Yes. I also briefly discuss in a later section (a) the CAISO's efforts to assess how much of a contribution preferred resources may make to meeting local reliability needs, and (b) Redondo Beach's reference to a specific CAISO study regarding renewable integration needs.

Q. Are you taking positions on any other aspects of the CAISO, SCE, SDG&E or Redondo Beach testimony that you do not address specifically in this testimony?

A. No, not at this time.

THERE ARE NO "SILVER BULLETS" OR "GRAND PLANS"; THE COMMISSION MUST INSTEAD TAKE REPEATED, INCREMENTAL MEASURES IN COMING YEARS TO ADDRESS SOUTH COAST LOCAL RELIABILITY CHALLENGES

Q. Do you think that any other party to this case expects that individual silver bullets or overall grand plans can at this time be identified and adopted with the certainty that they will be implemented and fully solve local reliability challenges in the LA Basin and San Diego?

A. No. I do not think any party actually believes that such silver bullets or grand plans exist. However, such hopes might be inferred from the advocacy of parties that express a preference for particular technologies or projects, including GFG, transmission and preferred resources. For example, the CAISO's desire to delay these hearings until its *2013-2014 Transmission Plan* is complete suggests it believes it might have especially valuable transmission projects to propose.[8] And the seeming precision and certainty of the utilities' alternative plans for meeting local needs might be interpreted as evidence that a grand plan can be identified now. But the Commission does not now have the ability to address the entirety of South Coast local reliability issues. Rather, over the next

[8] Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and 4 Schedules, September 16, 2013.

few years, the Commission will need to incrementally choose from a series of competing measures to gradually meet such needs.

ADVANTAGES AND DISADVANTAGES OF ALTERNATIVES FOR MEETING LOCAL RELIABILITY NEEDS

Q. Do you categorically oppose any particular technology, project or set of projects that have been proposed as a solution to South Coast reliability needs?

A. No. The Commission should be considering a wide range of options for meeting South Coast reliability needs. But each of these broad categories of resources – GFG, transmission and preferred resources – has positive and negative attributes for meeting local reliability needs.

Q. What are the positive and negative attributes of GFG as a means for meeting local reliability needs?

A. GFG offers several advantages that are key to its status as the default resource for system planning studies. First, GFG is capable of meeting the entirety of a local area's reliability needs. The technology is also proven, reliable and can be flexible. GFG can also meet local needs over a long time horizon. Finally, GFG may be the least-cost alternative.[9]

However, as GFG requires the combustion of a fossil fuel, it contributes to emissions of carbon dioxide and other pollutants. Each gas project will face a several-year development cycle with an uncertain outcome. A possible lack of emission permits in the LA Basin contributes to this uncertainty.[10] GFG may also increase customers' exposure to future gas price fluctuations.

Q. What are the positive and negative aspects of transmission as a means for meeting local reliability needs?

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[9] *SCE Track 4 Testimony*, Figure IV-7 (p. 42).

[10] *Id.*, 45:1-46:5

A. Transmission offers some key advantages of its own for meeting local needs. In particular, a single project may yield a large reduction in local needs, possibly larger than a typical 500 MW gas-fired combined cycle gas turbine unit.[11] Transmission lines are also long-lived assets and can provide benefits for many years. Further, transmission lines may offer other non-local benefits, such as reducing market energy prices or enabling the delivery of additional renewable energy.

But transmission has its own disadvantages. Transmission has a longer development cycle than GFG and the success of such development efforts are also uncertain. There are also limits on the number of feasible routes for new lines. Transmission lines, alone or together, cannot be expected to reduce a LRA's need to zero; rather, at some point some local generation is likely necessary to, if nothing else, maintain a LRA's voltage. Finally, a key challenge to relying on transmission in long-term reliability planning is the uncertainty of the benefit a specific line will yield once it is built. That is, it is not certain that a benefit of, for example, 1,000 MW as estimated in 2013 will actually be realized by a transmission line that goes into service in 2020.

An additional caveat is in order when considering transmission as an alternative for reducing local capacity needs. Transmission does not eliminate the need for generation; transmission merely moves such need from within a LRA to outside the LRA.[12] Such movements can be quite valuable if generation development is challenging, more expensive or has greater environmental impacts within a LRA and/or there is a surplus of generation outside the LRA. But new transmission will not necessarily reduce emissions or achieve the other benefits of avoiding the construction and operation of generation within a LRA. Transmission also may have negative environmental impacts of its own.

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11 For example, as discussed below, the potential local reliability benefit of SCE's proposed Mesa Loop-in project could be as high as 1,196 MW.

12 As discussed below and shown in Table 2, SCE assumed significant construction of GFG *outside* the LA Basin would occur in the three scenarios in which transmission is added to help meet local needs.

Q. What are the positive and negative aspects of preferred resources as a means for meeting local reliability needs?

A. Preferred resources offer their own key advantages.[13] The most notable is their reduced environmental impact compared to GFG and transmission. Another apparent advantage is the ability to deploy preferred resources more quickly than GFG and transmission options.[14] Small-scale preferred resources may also present lower development and operational risk because of their reliance on a higher number of project sites.

However, the planning for widespread use of preferred resources to meet local capacity needs is in its infancy and faces several key uncertainties, particularly as to the quantities that will be available, the ability of these quantities to meet local reliability needs, and the costs of such resources. Though preferred resources may be deployed more quickly, they also may not be as long-lived as GFG and transmission projects.

I summarize the positives and negatives of each of these types of resource in Table 1 below. As I have said, there are no "silver bullet" technologies that can be safely assumed at this time to meet all South Coast local reliability needs.

[13] This discussion focuses on Demand Response, Distributed Generation and Energy Efficiency, not storage.

[14] As discussed below and noted in Table 2, SCE's analysis assumed that the deployment of preferred resources begins in 2016 but does not assume generation and transmission alternatives are deployed until 2020.

TABLE 1

Positive and Negative Attributes of Major Alternatives for Meeting Local Reliability

Alternative	Gas Generation	Transmission	Preferred Resources a/
Positive	Can meet all local needs	Single project may yield large local benefits	Environmentally preferred
	Proven, reliable, flexible technology	Longest-lived assets	Rapid deployment
	Long-lived assets	May reduce energy costs	
	May be lowest cost b/	May allow delivery of more renewables	
Negative	GHG and other emissions c/	Longest development cycle	Uncertain quantities and duration
	Long development cycle	Siting and approval uncertain	Uncertain value in meeting local needs
	Siting and approval uncertain	Limits on feasible routes	Uncertain costs
	Limits on feasible sites and emission credits	Will not meet all local needs	Programs may be short-lived
	Increased exposure to gas price fluctuations	Benefit when built may differ from forecast	
Caveats		Moves, does not eliminate, generation need	
		Positive and negative environmental impacts	

Notes:

a/ List applies to Demand Response, Energy Efficiency and Distributed Generation, not storage.

b/ *SCE Track 4 Testimony* , Figure IV-7 (p. 42).

c/ *SCE Track 4 Testimony* , Figure IV-8 (p. 44), suggests LA Basin (gas) Generation option is alternative causing fewest GHGs.

IMPLICATIONS OF ALTERNATIVES' UNCERTAINTIES

Q. What are the implications of the fact that all the major alternatives face uncertainties as to their ability to be developed and – except generally for GFG – the contribution specific projects will make to meeting local reliability needs?

A. The uncertainties that face each of the major alternatives raise another key planning challenge: it will be impossible in this phase – or even after the CAISO files its *2013-2014 Transmission Plan* early next year – to come up with a multi-part resource plan in 2014 that can be implemented with the certainty that it will meet fully South Coast local reliability needs. That is, not only are there no "silver bullet" technologies, there are also no combined "grand plans" that can be adopted at this time.

Q. What are the implications of the inability to identify and implement at this time a "silver bullet" or "grand plan" to meeting South Coast local reliability needs?

A. In stating that it is not possible to adopt a silver bullet or grand plan that will with certainty meet South Coast needs, I am not arguing that the Commission cannot or should not take action at this time. Rather, my goal is to establish realistic expectations for what the Commission can and should do to start addressing these challenges. The Commission and other decision-makers should expect to resolve local reliability issues in the LA Basin and San Diego LRAs by taking incremental actions over time in various venues to authorize the development of resources that can be expected to contribute to meeting such need. In this Track 4, the Commission should start this long process by authorizing some initial resource procurement that can reasonably be expected to meet local reliability needs.

Q. Do you have any specific recommendations for Commission action consistent with this recommendation?

A. Yes. I believe the Commission should authorize SCE and SDG&E to each begin "all source" procurements for 500 MW in the near future, as they requested.[15] Such procurements can initiate the needed process of developing additional local resources in both areas.

Q. Are there any other issues that you believe warrant the Commission taking action at this time, in advance of Commission review of the CAISO's final *2013-14 Transmission Plan*?

A. Yes. The focus of the CAISO, SCE and SDG&E testimony was reliability in the year 2022. However, local reliability challenges may need resolution before then. For example, the CAISO found there will be needs of about 900 MW each in the LA Basin and San Diego LRAs in 2018, which total to about 1,800 MW total.[16] Though I am not

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15 *SCE Track 4 Testimony*, 55:1-58:10 and *SDG&E Track 4 Testimony, Anderson*, 12:3-15.

16 *CAISO Track 4 Testimony*, Table 9 (p. 19). Most of this LA Basin need could be met by extending the contract of an existing generator that might otherwise retire by 2018.

endorsing these findings herein,[17,18] even meeting more modest needs in just four years time may require rapid action; as discussed above, the deployment of preferred resources might be particularly useful for meeting such needs in a short time horizon.

SCE'S HYPOTHETICAL RESOURCE BUILD-OUTS TO MEET LA BASIN LOCAL RELIABILITY NEEDS

Q. Has any party provided information about the types of resources that might be built under alternate scenarios for meeting the utilities' local capacity needs?

A. Yes. SCE prepared hypothetical "resource plans" for purposes of its reliability modeling. This plan is summarized in Table 2 below.

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17 The CAISO's estimates of 2018 need are predicated on the assumption that certain OTC units will retire by December 31, 2017, but it is possible that such retirements could be delayed, which could greatly mitigate 2018 need. In making this observation, however, I am not suggesting the Commission rely on delays on OTC retirement in its planning decisions.

18 The CAISO's estimates of 2018 need also apparently rely on the assumption that load shedding is not permitted to mitigate the same N-1-1 contingency that drives the need estimate. (See *CAISO Track 4 Testimony*, 18:17-21.) I discuss an alternative to this assumption and its potential economic benefits below.

TABLE 2

SCE's Hypothetical "Resource Plans" Used for Reliability Modeling
(MW)

	LA Basin Generation	LA Basin Transmission	Preferred Resources	Regional Transmission	Sources:
GENERATION a/					
LA Basin					
CCGT	2,275	900	915	910	
CT	600	700	200	300	
DR	0	0	283	0	
EE	0	0	50	0	
Storage	0	0	50	0	
PV	0	0	229	0	b/ c/
Subtotal	2,875	1,600	1,727	1,210	
Out of LA Basin					
CCGT	0	0	0	455	
CT	0	600	400	600	
Subtotal	0	600	400	1,055	
Total	2,875	2,200	2,127	2,265	
Gas	2,875	2,200	1,515	2,265	
Preferred	0	0	612	0	d/
TRANSMISSION	0	1,196	1,196	1,604	e/ f/
MW TO LA BASIN	2,875	2,796	2,923	2,814	g/

Sources:

a/ Resource needs are not reduced to reflect potential 1,400 to 1,800 MW to be procured pursuant to Decision (D.) 13-02-015.

b/ Workpapers to *SCE Track 4 Testimony* (Exhibit No. SCE-01), Ch. IV-A, Table 1 (pp. 3-4).

c/ On-line dates for all gas generation is 2020. SCE assumed preferred resource capacity would be 20 percent of total in 2016 and increase by 20 percent per year through 2020.

d/ Sum of preferred resources in source b/ differs from data in source e/.

e/ *SCE Track 4 Testimony*, Table III-5 (p. 32). Assumes load shedding allowed to mitigate the N-1-1 contingency driving LA Basin need.

f/ Transmission capacity shown is amount of local capacity benefits; transmission lines may operate at different ratings in normal operations.

g/ Equals Subtotal of LA Basin Generation plus Transmission. Out of LA Basin resources do not directly contribute to meeting LA Basin local needs.

Q. Are there any caveats regarding SCE's modeling assumptions you wish to provide before discussing the implications of such assumptions?

A. Yes. These data are extremely hypothetical and should not be taken as any party's recommendation or forecast of future development. These data also only relate to SCE's modeling of LA Basin local needs and do not reflect SDG&E's modeling and analysis. Finally, SCE is already soliciting a portion of the above generation pursuant to Commission Decision (D.) 13-02-015, the decision in Track 1 of this docket. If SCE's current solicitation is successful, SCE will not have to obtain all the local capacity shown in Table 2 in subsequent steps.

Q. Given these caveats, do you have any observations about the SCE modeling assumptions shown on Table 2?

A. Yes. SCE's modeling presumes that significant amounts of gas-fired generation will be built to meet reliability needs. Each scenario presumes that at least 1,100 MW of GFG will be built in the LA Basin and at least an additional 400 MW of GFG will be built outside the LA Basin. This latter fact is consistent with my observation above that transmission projects do not eliminate the need for generation, but merely allow generation to be sited outside a LRA.[19]

COMMISSION SHOULD AUTHORIZE RESOURCE NEEDS ASSUMING LOAD SHEDDING MAY BE USED TO MITIGATE THE "N-1-1" CONTINGENCY THAT IS DRIVING ESTIMATES OF LA BASIN AND SAN DIEGO LOCAL NEED

Q. Are there any particular aspects of the CAISO's and utilities' modeling and analysis you think merits the Commission's special attention?

[19] SCE said it added generation outside the LA Basin for modeling purposes to isolate "the effect of OTC generation retirement within Southern California" but that this modeling is "not intended to suggest that additional resources are needed within the overall CAISO area, or suggest what kind of resources might be needed to meet system reliability needs". *SCE Track 4 Testimony*, 40:18-21.

A. Yes. In estimating local reliability needs, the CAISO assumed one particularly conservative modeling approach – an approach that is entirely discretionary and not required by reliability entities – that would substantially increase ratepayers' costs for a questionable increase in reliability.

Q. What is the modeling approach the CAISO is applying that you question?

A. Briefly, the CAISO assumes that "load shedding" should *not* be permitted to mitigate the key contingency that drives need in both San Diego and the LA Basin, which is the overlapping outages of the Sunrise Powerlink (Sunrise) and Southwest Powerlink (SWPL) transmission lines.[20] I also refer to this contingency as the key or critical"N-1-1" outage. I will discuss various aspects of this assumption below, including the additional costs it threatens to impose on customers and the CAISO's failure to justify its use of this method.

SIGNIFICANT COST IMPACT OF NOT ALLOWING LOAD SHEDDING FOR "N-1-1 SUNRISE / SWPL" CONTINGENCY

Q. What are the cost consequences to customers of not allowing load shedding to mitigate the key N-1-1 contingency?

A. The disallowance of load shedding as a means of managing the key N-1-1 contingency would increase the amount of local capacity needed in the LA Basin and San Diego LRAs. The impact on such local needs of this assumption is shown in Table 3 below.

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[20] *SCE Track 4 Testimony*, 27:9-11.

TABLE 3

Impact of Load Shedding to Mitigate Key N-1-1 Outage on Local Capacity Needs in the LA Basin and San Diego Local Reliability Areas (MW)

UTILITY	SCE a/				SDG&E b/				Notes:
LOCAL CAPACITY NEED									
Scenario	Generation Only		Mesa Loop-In		Generation Only		IV - SONGS DC		
Load Shedding?	Yes	No	Yes	No	Yes	No	Yes	No	
SCE (LA Basin):	2,802	3,240	1,606	2,506	2,802	2,802	2,251	2,251	
SDG&E:	1,270	1,270	1,270	1,270	1,320	1,470	370	620	c/
Total:	4,072	4,510	2,876	3,776	4,122	4,272	2,621	2,871	
INCREASE IN NEED DUE TO DISALLOWANCE OF LOAD SHEDDING									
SCE (LA Basin):	438		900						d/
SDG&E:					150		250		
SOURCES									
Sources:	SCE Track 4 Testimony				SDG&E Track 4 Testimony				
Page(s):	31A (errata) and 32				10	11	10	11	
Table(s):	III-IV Errata (SDG&E) & III-5 (SCE)				1	2	1	2	

Notes:
- a/ SCE did not provide "No Load Shedding" capacity estimates for its Regional Transmission scenario.
- b/ SDG&E's estimates showed load shedding assumption had no impact on "Devers-NCGen AC" alternative.
- c/ Results for SDG&E and Totals provided by SCE printed in grey text and *vice verse*. Both utilities included 300 MW Pio Pico project in their modeling.
- d/ Increase for each Scenario equals "Need" with "No" to load shedding minus "Need" with "Yes" to load shedding.

Q. Please explain the computations you show in Table 3.

A. In Table 3, I simply array the two utilities' findings of local need in the LA Basin and San Diego LRAs in the "with" and "without" load shedding cases. As need is higher without load shedding, the impact of this approach on need is simply the need estimated "with" load shedding subtracted from need estimated "without" load shedding. For example, if load shedding is allowed, SCE estimates its need in the scenario in which need is met entirely with LA Basin Generation to be 2,802 MW, but need rises in this scenario by 438 MW to 3,240 MW if load shedding is not allowed.

Q. Is it plausible that a load shedding scheme in the SDG&E area to manage this N-1-1 contingency on its system could reduce planning requirements in *both* the SCE and SDG&E territories?

A. Yes. In addition to their testimony on this matter, both utilities affirmed the reasonableness of this conclusion in response to TURN data requests.[21] These responses are provided as Attachments 2 and 3, respectively.[22]

Q. Do you have any observations regarding the data in Table 3 that merit the Commission's attention?

A. Yes. The increases in the amounts of capacity ratepayers need to support if load shedding is not allowed to mitigate the critical N-1-1 contingency can be significant. And for both utilities, these increases reduce the benefits of the transmission options relative to the benefits of generation options. For example, the local reliability benefits of SCE's Mesa Loop-in project – which based on the information SCE provided in its testimony appears to be a promising addition – would fall by 462 MW or over one-third, from 1,196 MW to 734 MW.[23]

Q. Can you translate the MW quantity of these higher needs to a dollar impact on ratepayers?

A. Yes. SCE provided estimates of the Net Present Value (NPV), as of January 1, 2013, of the "net costs" incurred from 2016 to 2032 in each of its four scenarios assuming load shedding would be permissible to mitigate the key N-1-1 contingency.[24] Based on SCE's estimates, I prepared estimates of the increase in net costs to SCE customers in each scenario of the assumption that load shedding is not allowed to mitigate the key N-1-1 contingency. Briefly, for each of SCE's scenarios, I computed the average net cost per

21 SCE's response to Question 9 of TURN's 1st Data Request and SDG&E's response to Question 15 of TURN's 1st Data Request.

22 As discussed below, SDG&E has already developed such a load shedding scheme for this contingency.

23 See Table 3. The capacity of the Mesa Loop-in project for reliability purposes "with load shedding" is 2,802 MW minus 1,606 MW, which is 1,196 MW. The project's capacity "without load shedding" is 3,240 MW minus 2,506 MW, or 734 MW.

24 SDG&E did not provide such cost estimates.

MW for meeting the 2,802 of local need SCE found in its LA Basin Generation case in its "with" load shedding cases, and multiplied that average by the amount of additional local capacity SCE would need to procure in the "without" load shedding cases to estimate the NPV of customers' added net costs in those scenarios. These results are shown in Table 4 below.

Q. Do you have any caveats to offer about the results shown in Table 4?

A. Yes. SCE cautioned that their results are only approximations.[25] Given the imprecision of SCE's results, and the back-of-the-envelope use I have made of them, I offer an even stronger caution that my results are only approximations. I have additional concerns about SCE's estimates that I describe below.

[25] *SCE Track 4 Testimony*, 41:23.

TABLE 4

Impact of Load Shedding to Manage Key N-1-1 Contingency on SCE and SDG&E Customers' "Net Costs" (Net Present Value as of 1/1/13 of Net Costs Incurred from 2016 to 2032)

		Scenario				
		LA Basin Generation	LA Basin Transmission	Preferred Resources	Regional Transmission	Sources & Notes
LA BASIN NEED AND COST "WITH LOAD SHEDDING ALLOWED"						
Need	MW	2,802				a/
Net Cost	$MM	1,251.7	1,582.0	1,853.9	2,452.1	b/
Average Net Cost	$/kW	446.7	564.6	661.6	875.1	c/
LA BASIN NEED AND COST "WITHOUTLOAD SHEDDING"						
Added Need	MW	438	900	900	900	d/
Added Net Cost	$MM	195.7	508.1	595.5	787.6	e/
	%	16	32	32	32	f/
Total Net Cost	$MM	1,447.4	2,090.1	2,449.4	3,239.7	g/

Sources:
a/ Table 3.
b/ Workpapers to *SCE Track 4 Testimony* (Exhibit No. SCE-01), Ch. IV-A, , pp. 20, 22, 24 and 27.
c/ Equals "Net Cost" divided by "Need".
d/ Table 3. Does not reflect possibility that benefits of SCE's "Regional Transmission" project would be further reduced in "without load shedding" case.
e/ Equals "Added Need" times "Average Net Cost".
f/ Equals "Added Net Cost" divided by "Net Cost"
g/ Equals "Net Cost" plus "Added Net Cost".

Q. Despite their approximate nature, do you think your results help illustrate the magnitude of the costs that could be imposed by the CAISO's more stringent modeling approach regarding load shedding?

A. Yes. Except as noted below, I am comfortable that my adaptation of SCE's results provides a good start at estimating the added costs SCE customers would need to pay to meet reliability criteria in a system in which load shedding is not allowed to mitigate the critical N-1-1 contingency. These estimates show the NPV of the extra net costs will run into hundreds of million dollars, as shown in the line labeled "Added Net Cost" in Table 4.

Q. Do you give any of the scenario cost results in Table 4 more weight than the others?

A. Yes. I think the LA Basin Transmission and Preferred Resources scenarios are the most plausible, suggesting that the added net cost of the load shedding criterion would be at least several hundred million dollars. I do not think the LA Basin Generation scenario is reasonable, as it anticipates that all needs will be met by local gas generation. The Regional Transmission scenario, as SCE has developed it, does not seem like a reasonable outcome because significant extra costs would be incurred for modest local reliability benefits.[26] However, the Regional Transmission scenario may give the best view at the marginal costs of meeting local reliability needs caused by adherence to the "no load shedding" assumption, as the costs of meeting local reliability will likely rise as the total MW need rises.

Q. Do you have any data to offer regarding the capital costs in SCE's estimates of the scenarios' costs and how they might be increased by the CAISO's more stringent approach?

A. Yes. SCE summarized the capital costs of each of its scenarios in response to Question 5 of the Energy Division's 2nd Data Request. This response, provided as Attachment 4,

[26] Table 2 above shows increased imports for reliability purposes into the LA Basin of only 408 MW in the Regional Transmission scenario, which might be further reduced if load shedding is not allowed as mitigation for the key N-1-1 contingency.

shows that the capital costs to be invested on behalf of ratepayers in the three least-costly options have a Present Value (PV) of about $3 billion as of January 1, 2013 and the PV of the fixed costs of the Regional Transmission scenario is about $4 billion. A need for SCE customers to support additional investments due to a reliability criterion that does not permit load shedding to manage the key N-1-1 contingency would require ratepayers to support proportionately higher investments, as shown in Table 5 below. In the two middle-cost scenarios, these additional capital costs total about one billion dollars. Additional capital costs are over a billion dollars in the Regional Transmission scenario.

TABLE 5

Impact of Load Shedding to Manage N-1-1 Contingency
on SCE and SDG&E Customers' Capital Costs
(Net Present Value as of 1/1/13 of Net Costs Incurred from 2016 to 2032)

		Scenario				
		LA Basin Generation	LA Basin Transmission	Preferred Resources	Regional Transmission	Sources & Notes
LA BASIN NEED AND COST "WITH LOAD SHEDDING ALLOWED"						
Need	MW	2,802				a/
Capital Costs	$MM	3,140	2,970	3,120	3,920	b/
Average Capital Cost	$/kW	1,120	1,060	1,110	1,400	c/
LA BASIN NEED AND COST "WITHOUTLOAD SHEDDING"						
Added Need	MW	438	900	900	900	d/
Added Capital Costs	$MM	490	950	1,000	1,260	e/
	%	16	32	32	32	f/
Total Capital Costs	$MM	3,630	3,920	4,120	5,180	g/

Sources:
- a/ Table 3.
- b/ Attachment 4 (SCE response to Question 5 of Energy Division's 2nd Data Request).
- c/ Equals "Capital Costs" divided by "Need". Results rounded to three significant dig
- d/ Table 3. Does not reflect possibility that benefits of SCE's "Regional Transmission" project would be further reduced in "without load shedding" case.
- e/ Equals "Added Need" times "Average Capital Cost". Results rounded to three significant digits.
- f/ Equals "Added Capital Costs" divided by "Capital Costs".
- g/ Equals "Capital Costs" plus "Added Capital Costs". Results rounded to three significant digits.

Q. Do you have any other comments on SCE's estimated needs that are relevant to consideration of the scenarios' potential added net costs if load shedding if not allowed?

A. Yes. In its testimony, SCE suggested that the more stringent CAISO method might increase LA Basin reliability needs to more than 436 MW.[27] Any such increase in need would increase the negative impact of the no load shedding assumption.

Q. Do you have any other comments on SCE's cost data that are relevant to consideration of the potential added net costs of a no load shedding criterion?

A. Yes. As noted above, SCE's estimates are NPVs as of January 1, 2013 of the net costs and capital costs it estimated its customers would bear from 2020 to 2032 (or 2016 to 2032 in the Preferred Resources scenario). As I read SCE's workpapers, SCE's analysis thus only considers 13 years of costs of added transmission and generation assets, rather than their full life-cycle costs. The longer-term costs of meeting local need – and the added costs of also meeting a more limiting approach – may thus be higher than shown in Tables 4 and 5.

In addition, in the scenarios in which transmission investment is assumed, SCE appears to be computing annual transmission capital costs assuming they will escalate from year-to-year, even though ratepayer payments for such assets tend to be front-loaded. This convention may also understate the estimated costs of these scenarios.[28] And as I read SCE's workpapers, it does not appear that SCE is including in transmission costs the higher rate-of-return transmission assets are granted by the Federal Energy Regulatory Commission. If so, SCE's costs may further understate the scenarios' costs.

Further, the analyses shown in Tables 4 and 5 were based on the average costs SCE estimated for each scenario. It is plausible that the marginal costs of meeting incremental

[27] *SCE Track 4 Testimony*, 6:22-7-4 (including footnote 7 and Figure II-1 (p. 8)). This figure differs slightly from the change in need shown in Table 3.

[28] SCE Workpapers to Exhibit No. SCE-01 (*SCE Track 4 Testimony*) / Ch. IV-A, pp. 22, 24 and 27.

local need are even higher. If so, the impact of the additional need resulting from the CAISO's more conservative approach would be yet higher.

Finally, the NPV of these costs as of January 1, 2020, when customers would begin to pay for the bulk of such investments, will be almost double the 2013 NPVs shown in Table 4, given SCE's cost of capital of approximately ten percent.[29]

Q. Does the CAISO's unwillingness to accept load shedding to manage the key N-1-1 contingency have other planning implications before the year 2022?

A. Yes. SDG&E witness Jontry testified that this method currently results in an increase in San Diego local capacity needs of 400 MW.[30] These impacts are higher than the range of zero to 250 MW SDG&E reported in its testimony for 2022 shown in Table 3 above. The no load shedding assumption may thus inflate need estimates made based on near term conditions. This same impact may be occurring in SCE's territory as well.

Q. Can you offer any assessment of the impact of the assumption that load shedding is not allowed as mitigation for the key N-1-1 contingency on the costs to SDG&E customers?

A. Yes, though these estimates are also only rough approximations, particularly since SDG&E did not provide its own estimates of the costs of its alternatives. Table 3 above shows the CAISO's more conservative standard reduces needs in the San Diego LRA by zero, 150 or 250 MW in SDG&E's three scenarios. Multiplying these changes in need by a "net cost" of $600/kW – the rough average of the two most plausible scenarios from Table 4 – yields an increased NPV as of January 1, 2013 from zero to $150 million of the costs over the period of 2020 to 2032. Performing the same operation on the capital costs shown in Table 5 yields an increased NPV of capital costs ranging from zero to $250 million for the same period. These estimates are subject to all the above caveats regarding SCE's cost estimates plus the additional caution that SDG&E's costs may differ from SCE's.

29 *Id.*, pp. 19, 21, 23 and 26.
30 *SDG&E Track 4 Testimony, Jontry*, 7:18-20.

Q. What are the implications for customers of the above analysis of the costs of the CAISO's unwillingness to accept load shedding to manage the N-1-1 contingency?

A. The above estimates show that reliability modeling assumptions can have a significant impact on customer costs. Yet, as discussed below and in Appendix I, it is not clear the state's decision-makers – nor even CAISO management – has clearly reviewed the trade-off between these higher costs and reliability. The Commission – which has in the past said it would not pursue a policy of "reliability at any cost"[31] – should consider this trade-off in this docket. If the Commission does not wish to make a final determination on this matter at this time, the Commission can still decide on its own to restrict any authorizations it makes in the near future to the long-term needs that exist based on an approach that allows load shedding to mitigate the critical N-1-1 contingency.

CAISO APPLICATION OF THIS MODELING OF THE KEY N-1-1 CONTINGENCY IS DISCRETIONARY AND HAS NOT BEEN VETTED WITH INDUSTRY STAKEHOLDERS

Q. Do the various industry reliability standards require the CAISO to use the more stringent modeling approach that does not allow the consideration of load shedding in response to the key N-1-1 contingency in its modeling and analysis?

A. No. The entities with responsibility for setting electric reliability standards all allow load shedding to be used to mitigate an N-1-1 contingency like the Sunrise / SWPL outage that the CAISO, SCE and SDG&E all cite as a key contingency driving local need in the LA Basin and San Diego.[32] For the benefit of the record, I provide documents documenting the discretionary nature of this criterion in Appendix A, including several from the CAISO itself.

Q. How does the CAISO justify its decision not to allow load shedding to manage the key N-1-1 contingency in its modeling?

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31 D.05-10-042, p. 7.

32 *CAISO Track 4 Testimony*, 18:17-21, *SCE Track 4 Testimony*, 24:11-17 and Figure III-3 (p. 25), and *SDG&E Track 4 Testimony, Jontry*, 3:5-7 and 6:19-21.

A. In response to Question 2 of DRA's 4th Data Request, the CAISO simply cited witness Sparks's Rebuttal Testimony in Application (A.) 11-05-023 regarding "Load Shedding and Special Protection Schemes".

In that testimony, witness Sparks stated that "although NERC TPL 003 *permits* load shedding as a mitigation for an N-1-1 contingency, the standard does not *require* the ISO, as the Planning Coordinator, to approve an automatic load shedding [Special Protection Scheme] under all such circumstances".[33]

He justified the CAISO's decision not to permit a load shedding scheme as a means of mitigating the Sunrise / SWPL outage by stating:

> I explained that with the more likely N-1-1 as the most limiting contingency, the ISO did not believe that it would be prudent planning to rely on an automatic load shedding SPS.
>
> This is because the history of transmission line outages due to fires and equipment failures in the area and the configuration of the system indicate that outage risks and consequences are high. The Imperial Valley substation is a major source of imported power for three different utilities: SDG&E, IID, and CFE. This is not only evidence of the criticality of this substation, but also the level of exposure to operational coordination issues and failures. Relying on load shedding as a primary mitigation measure is an indication that the system is being planned and operated at a very high stress level, and with very little margin for error. Based on this information, it is not prudent to plan and operate the Imperial Valley system with currently expected high outage risks and consequences at a very high stress level and with very little margin for error.[34]

Q. Do you believe the Commission should accept the above analysis as the basis for a decision on whether load shedding should be permitted to manage the N-1-1 contingency that is driving local capacity need estimates in this track?

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[33] *Rebuttal Testimony of Robert Sparks*..., A.11-05-023, June 6, 2012, 10:20-22. Emphasis original. NERC is the acronym for North American Electric Reliability Corporation, which develops and enforces national reliability standards for bulk electric systems.

[34] *Id*., 8:22-9:9. SPS is the acronym for Special Protection Scheme, IID is the acronym for the Imperial Irrigation District and CFE is the acronym for Comision Federal de Electricidad.

A. No. Mr. Sparks's analysis may read reasonably, but may also be reasonably questioned using very basic public data. Nor does his analysis bear evidence that the CAISO has documented or communicated this decision publicly or undertaken a public review in a CAISO stakeholder or similar process, despite the CAISO's history of documenting, communicating and discussing its local reliability criteria.[35]

Q. What evidence can you cite that should cause the Commission and other parties to question the reasonableness of the decision not to permit load shedding to manage the key N-1-1 contingency in this case?

A. The first set of evidence is the cost data I presented above. Those data show that a decision to disallow load shedding to manage the key N-1-1 contingency carries very significant negative cost consequences for customers.

In addition, SDG&E witness Jontry testified that SDG&E has developed just such a load shedding scheme that has been certified by the Western Electricity Coordinating Council (WECC).[36] The interest of the relevant retail utility in developing such a tool to manage reliability on its system suggests strongly that SDG&E believes that its own customers will benefit from giving the CAISO the ability to deploy a load shedding scheme.

Further, though neither SDG&E nor SCE state they disagree with the CAISO's more conservative approach, they both exercised their own discretion to file testimony that framed the impacts on need and cost of the more stringent standard. The obvious interest of the two retail utilities in managing their customers' costs by using load shedding to mitigate the key N-1-1 contingency that drives their customers' local capacity needs should speak loudly to this Commission and other interested parties about the load shedding scheme's potential cost benefits.

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35 See Appendix I.

36 *SDG&E Track 4 Testimony, Jontry*, 7:1-3. The WECC is the Regional Entity responsible for coordinating and promoting the reliability of the bulk electric system in the western United States and portions of Canada and Mexico.

Q. Can you provide information how SDG&E's load shedding scheme would actually operate in practice?

A. Yes. SDG&E provided a description of how its approved load shedding scheme would operate in response to Question 14 of TURN's 1st Data Request. This response is provided as Attachment 5.

Q. What are the consequences for reliability of allowing load shedding in the hypothetical overlapping N-1-1 Sunrise / SWPL Outage contingency?

A. Allowing load shedding in case of a combined Sunrise / SWPL outage exposes some SDG&E customers to a slightly higher possibility of being interrupted temporarily.

Q. Has the Commission made findings rejecting the use of load shedding to manage the specific N-1-1 contingency?

A. Yes. In particular, the Commission adopted the CAISO's position on this issue in D.13-03-029 issued in A.11-05-023.[37]

Q. Should the Commission feel bound by this seeming precedent to accept the CAISO's position on this issue?

A. No. As a general rule, Commissions are not legally bound by the actions of prior Commissions. And in this case, given the documented negative cost implications discussed above that are clearly tied to the more conservative approach, the Commission should take a fresh look at this assumption in its decision in this Track 4.

Q. Should Commission consideration of the allowance of load shedding to mitigate the key N-1-1 contingency somehow be taken as a lack of concern about reliability?

A. No. Rather, Commission review of this assumption should be taken as a sign that it cares about balancing the two potentially conflicting "goods" of reliability and low customer costs. As stated above, the Commission has said it does not support a policy of

[37] D.13-03-029, p. 11.

"reliability at any cost," but instead implicitly requires that reliability needs to be cost-effective. The evidence above suggests that the allowance of load shedding in one particular case could save customers substantial amounts of money. Commission consideration of this approach is appropriate given the clear presentation of anticipated overall cost reduction.

Q. Are you saying that the Commission should necessarily decide its policy regarding the use of load shedding to manage the key N-1-1 contingency in this docket once-and-for-all?

A. No, not necessarily. I am open to the idea that the CAISO's approach might be shown to strike an appropriate balance between reliability and cost. But such a showing should be based on an open analysis and discussion of the benefits and costs of reliance on a standard that exceeds NERC, WECC and the CAISO's own written standards. Until such a process can be conducted, I recommend the Commission not require customers to support any commitments that can be attributed to the imposition of the CAISO's more conservative approach.

OTHER ISSUES

ANALYSIS OF ABILITY OF PREFERRED RESOURCES MEET LOCAL RELIABILITY NEEDS

Q. Do you have concerns with any other planning criteria that the CAISO and utilities are applying or proposing in this Track 4?

A. Yes. The CAISO process and utilities' intent to analyze the ability of preferred resources to meet local reliability needs is a matter that merits the Commission's attention.

Q. What are the CAISO and utilities proposing as to analyzing the ability of preferred resources to meet local capacity needs?

A. All three entities believe that additional analysis is needed to test if and how preferred resources will meet local reliability needs. SCE and SDG&E testified that they have been discussing this issue with the CAISO and expect to continue such efforts.[38] Though its testimony on this matter was limited, the CAISO has started an effort within its 2013-2014 Transmission Planning Process (TPP) to develop a means of estimating the contributions preferred resources can make to meeting local needs. Attachment 6 is a presentation the CAISO made on this subject to its TPP stakeholder meeting on September 25, 2013.[39]

Q. Do you support analysis of if and how preferred resources can meet local reliability needs and the use of the findings of such analyses in the Commission's future resource authorizations?

A. Yes. It is important to analyze the ability of preferred resources to meet local reliability needs and to base future authorizations on the vetted results of such analyses.

Q. Do you have any concerns with the direction of the CAISO's current study?

A. Yes. First, any analyses submitted with the CAISO's *2013-2014 Transmission Plan* will only be a first cut at the issue. I make this statement not as a criticism of what the CAISO may file, but to caution parties and the Commission against treating the first set of results as being conclusive.

Further, significant amounts of preferred resources – including solar photovoltaic resources – already exist in the CAISO system, along with other conventional resources with contractual obligations or technical limits on their ability to respond to local system conditions. These resources' contributions to meeting local reliability are now factored into local capacity analyses by use of their resource-specific Net Qualifying Capacities

[38] *SCE Track 4 Testimony*, 19:7-9 and 63:24-64:2 and *SDG&E Track 4 Testimony, Anderson*, 4:13-16.

[39] The presentation is available at http://www.caiso.com/Documents/Presentation-PreliminaryReliabilityAssessmentResults-Sep25_2013.pdf at slides 178-189 of the Acrobat (pdf) document.

(NQCs). Any new or revised methodology for determining preferred resources' ability to contribute to meeting local capacity should recognize that this approach has thus far seemed to appropriately count preferred resources' contributions to local reliability.

Q. What actions do you recommend the Commission take regarding this issue?

A. The Commission does not have a basis to draw conclusions on this matter at this time. When it gets more information, the Commission should take the time to make its own assessment of preferred resources' ability to support local capacity needs. Its first opportunity to make such analyses will apparently come when the CAISO provides the results of its *2013-2014 Transmission Plan* in this Track 4 of this docket early next year.

To my knowledge, there is no NERC, WECC or other formal guidance on how to count the contribution of preferred resources to meeting local reliability. Rather, the state is developing its own criteria on the fly. The Commission thus can and should take the lead in developing such standards.

Q. Do you have any other comments to make about forthcoming analyses of the ability of preferred resources to meet local capacity needs?

A. Yes. When discussing the ability of preferred resources to meet local capacity needs, SCE's testimony often uses the term "effectiveness". However, another measure of a resource's ability to meet local capacity needs is already formally labeled as its "effectiveness factor". Future discussion of these issues should avoid conflating these two concepts.

REDONDO BEACH'S REFERENCE TO CAISO RENEWABLE INTEGRATION STUDY SHOULD BE IGNORED

Q. What is your concern with the testimony filed on behalf of the City of Redondo Beach?

A. The Redondo Beach testimony appears to favorably cite a CAISO study that found that 4,600 MW of new flexible generation capacity will be needed to integrate renewable resources in 2020.[40] Though renewable integration is not currently an issue in this docket,[41] it is important for the record to reflect the facts that:

- This particular CAISO forecast has never been litigated by this Commission. Parties – including the CAISO and TURN – to Rulemaking (R.) 10-05-006, the docket in which the above-cited CAISO study was submitted to this Commission, agreed to a settlement stating "[t]here is general agreement that further analysis is needed before any renewable integration resource need determination is made" ,[42] and
- The Commission appears skeptical it will need to authorize significant amounts of new resources solely for the purpose of integrating renewables.[43]

The Commission should not base any action in this Track 4 or other tracks of this docket based on this portion of the Redondo Beach testimony.

CONCLUSION

Q. Please reiterate your findings and conclusions.

A. As discussed above, I offer the following conclusions and recommendations regarding two major issues in this case:

- The Commission will need to authorize a number of steps over the next several years to allow South Coast reliability needs to be met, and should start by

[40] *Testimony of Jaleh Firooz…on Behalf of the City of Redondo Beach*, August 26, 2013, page 21 of the attachment titled "Study of an Environmentally Superior Alternative…"

[41] Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and 4 Schedules, September 16, 2013 (September 16 Ruling).

[42] D.12-04-046, p. 6.

[43] September 16 Ruling, p. 6.

authorizing SCE and SDG&E to each solicit 500 MW of additional resources on an "all source" basis.

- The Commission should base any findings of need on modeling analyses that allow the use of load shedding to mitigate the key N-1-1 contingency that drives South Coast local resource needs and not the CAISO's more conservative modeling approach.

On two other issues, I recommend:

- The Commission take the lead in analyzing the ability of preferred resources to contribute to meeting local reliability needs.
- The Commission ignore Redondo Beach's reference to the CAISO's study that found 4,600 MW of new resources will be needed for renewable integration.

Except as stated explicitly in the testimony above, I am not taking positions on any other issues in this docket at this time.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT 1

to Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

Resume of Kevin Woodruff

RESUME

Kevin Woodruff
Principal, Woodruff Expert Services

EXPERIENCE

WOODRUFF EXPERT SERVICES 1100 K Street, Suite 204 Sacramento, California 95814 916-442-4877 (voice) 916-442-2029 (fax) kdw@woodruff-expert-services.com November 2002 –	**PRINCIPAL** Analyze complex policy and business issues faced by electric utilities, generators, customers, and other industry players. Communicate to clients analytic findings and corollary recommendations for action. Help clients communicate findings and recommendations to other parties, including preparing expert testimony for and supporting litigation efforts.
HENWOOD ENERGY SERVICES, INC. (aka Ventyx and acquired by ABB May 2010, previously aka Global Energy Decisions) April 1988 – November 2002	**PRINCIPAL CONSULTANT (as of July 1992)** Helped manage Henwood's transition into leading supplier of electric power system and market analytic software by managing complex software development and implementation projects and managing the development, marketing, and sales of software products. Helped develop Henwood's power market analysis consulting practice into national leader by managing individual projects, managing and developing other staff to provide such services, identifying and developing new and enhanced services, and marketing and selling services to new and existing clients. Provided variety of consulting services to clients with interests in energy utility industry, including preparing expert testimony and supporting litigation efforts, analyzing, modeling, and forecasting operations of power systems, power markets, and individual generating units, forecasting utility and project revenues, costs, and rates, and analyzing and consummating business transactions.
CALIFORNIA STATE UNIV, SACRAMENTO September 1994 – May 1995 (part-time)	**LECTURER IN MANAGEMENT** Taught upper division courses in Finance.
SIERRA ENERGY AND RISK ASSESSMENT May 1986 – April 1988 November 1985 – May 1986 (part-time)	**STAFF CONSULTANT** Provided clients analysis of gas and electricity project economics and utility revenues, costs, and rates.
PRIOR EXPERIENCE	Five years with private legislative reporting firm; California state economic development, regulatory, and tax agencies and Legislature; and labor organization.

EDUCATION

A.B., Economics, University of California, Berkeley, 1976
M.B.A, California State University, Sacramento, 1990

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ADDENDUM 1

to Resume of Kevin Woodruff

EXPERIENCE WITH WOODRUFF EXPERT SERVICES

CLIENT	PROJECTS
THE UTILITY REFORM NETWORK 115 Sansome Street, Suite 900 San Francisco, CA 94104 415-929-8876 Mr. Bob Finkelstein, Legal Director Mr. Matt Freedman, Staff Attorney	**ANALYZE IOUs' PROPOSALS TO DEVELOP OR ACQUIRE POWER PLANTS. Sep 03 – present.** Review, analyze, comment, and testify on California Investor-Owned Utilities' (IOUs') various plans to purchase output from and/or take ownership of specific power plants, both conventional and renewable. **MONITOR CALIFORNIA IOUs' SHORT- AND MID-TERM ELECTRIC PROCUREMENT. Aug 03 – present.** Review, analyze, and comment on California IOUs' short- and mid-term electric power procurement and related activities by participating in their confidential Procurement Review Groups. **ANALYZE ELECTRIC RESOURCE PLANNING AND ADEQUACY POLICIES. May 03 – present.** Review, analyze, comment and testify on California electric resource planning issues, including Resource Adequacy policies, the development of new power plants, the integration of renewable resources and transmission planning.
OFFICE OF THE ARKANSAS ATTORNEY GENERAL, CONSUMER UTILITIES RATE ADVOCACY DIVISION 323 Center Street, Suite 200 Little Rock, AR 72201 501-682-1321 Mr. M. Shawn McMurray, Senior Assistant Attorney General Mr. Emon Mahony, Assistant Attorney General	**ANALYZING UTILITY PROPOSAL TO ALLOCATE "WHOLESALE BASELOAD" RESOURCES TO CUSTOMERS. Jul 12 – Apr 13.** Analyzing Entergy Arkansas, Inc. (EAI) proposal to allocate certain nuclear and coal resources now allocated to EAI's wholesale portfolio back to EAI jurisdictional customers. (APSC Docket No. 12-038-U) **ANALYZING PROPOSAL TO INSTALL ENVIRONMENTAL CONTROLS ON COAL POWER PLANT. Mar 12 – Jul 13.** Analyzing proposal of Southwestern Electric Power Company and other owner to install environmental controls at the coal-fired Flint Creek Power Plant. (APSC Docket No. 12-008-U) **ANALYZING ENTERGY ARKANSAS, INC. FUTURE SYSTEM PLANNING AND OPERATION OPTIONS. Jun 10 – Oct 12.** Analyzing alternatives for EAI to plan and operate its electric generation and transmission systems upon its withdrawal from the Entergy System Agreement. (APSC Docket No. 10-011-U) **ANALYZED TRANSMISSION PLANNING ISSUES. Feb 09 – Aug 09.** Analyzed proposals to restructure Entergy's transmission planning processes. (APSC Docket No. 08-136-U) **ANALYZED TRANSMISSION COST RECOVERY ISSUES. Mar 10 – Apr 10.** Analyzed utility proposals to expedite recovery of transmission and related costs. (APSC Docket Nos. 09-074-U and 09-084-U)

CLIENT	PROJECTS
ARKANSAS ATTORNEY GENERAL (continued)	**ANALYZED PROPOSAL TO INSTALL ENVIRONMENTAL CONTROLS ON COAL POWER PLANT. Mar 09 – Dec 09.** Analyzed proposal of EAI and other owners to install scrubbers and low NOx burners at the coal-fired White Bluff Steam Electric Station. (APSC Docket No. 09-024-U) **ANALYZED UTILITY PROPOSAL TO PURCHASE POWER PLANT. Nov 07 – Jun 08.** Analyzed EAI proposal to purchase Ouachita (combined cycle power) Plant and related wholesale resale, cost allocation and ratemaking issues. (APSC Docket No. 06-152-U)
ATTORNEY GENERAL OF WASHINGTON, PUBLIC COUNSEL SECTION 800 5th Street, Suite 2000 Seattle, WA 98104-3188 206-389-3055 Mr. Simon J. ffitch, Senior Assistant Attorney General, Section Chief	**ANALYZING UTILITY CONTRACT FOR PURCHASE OF "COAL TRANSITION POWER". Sep 12 – Mar 13.** Analyzing Puget Sound Energy (PSE) proposal for "Coal Transition Power Purchase Agreement" (PPA) for output of TransAlta's Centralia coal plant. (WUTC Docket No. 121373) **ANALYZED UTILITY POWER SUPPLY COST FORECAST AND PROPOSED POWER CONTRACT. Feb 09 – Dec 09.** Analyzed proposal of Avista to assign to Avista Utilities a PPA and related contracts related to the Lancaster (combined cycle) Generating Facility and other aspects of Avista's forecast of its 2010 power supply costs. (WUTC Docket No. 090134)
DIVISION OF RATEPAYER ADVOCATES of the CALIFORNIA PUBLIC UTILITIES COMMISSION 505 Van Ness Avenue San Francisco, CA 94102 415-703-1418 Mr. Scott Logan, Regulatory Analyst	**ANALYZED COST-EFFECTIVNESS OF PROPOSED TRANSMISSION LINES.** **Dec 06 – Jan 09.** Led team of consultants analyzing cost-effectiveness of San Diego Gas & Electric Company's proposed Sunrise Powerlink transmission line. **Aug 05 – Jan 07.** Led team of consultants analyzing cost-effectiveness of Southern California Edison's proposed Devers–Palo Verde No. 2 Transmission Line Project (DPV2).
MAINE PUBLIC ADVOCATE OFFICE 112 State House Station Augusta, ME 04333-0112 207-287-2445 Mr. Richard Davies, Public Advocate Ms. Agnes Gormley, Senior Counsel	**ANALYZED PROPOSED TRANSMISSION LINE. Aug 10 – Sep 10.** Performed review of feasibility and cost-effectiveness of Algonquin Power Corporation's proposed Northern Maine Interconnect.
MAINE PUBLIC UTILITIES COMMISSION 242 State Street, State House Station 18 Augusta, ME 04333 207-287-1394 Mr. Chuck Cohen, Hearing Examiner	**ANALYZED COST-EFFECTIVENESS OF PROPOSED TRANSMISSION LINE. Oct 08 – Jan 09.** Initiated analysis of cost-effectiveness of Maine Public Service and Central Maine Power Company's proposed Maine Power Connection.

CLIENT	PROJECTS
NEVADA OFFICE OF THE ATTORNEY GENERAL, BUREAU OF CONSUMER PROTECTION 555 E. Washington Avenue, Suite 3900 Las Vegas, NV 89101 702-486-3129 Mr. Eric Witkoski, Chief Deputy Attorney General	**ANALYZED COST-EFFECTIVNESS OF PROPOSED GENERATION AND TRANSMISSION RESOURCES.** **Jun 07 – Sep 07 and Jul 08 – Aug 08.** Reviewed and analyzed resource plans and amendments filed by the Nevada Power Company and Sierra Pacific Power Company. **Jun 06 – Nov 06.** Led team of consultants analyzing proposals to build significant new generation and transmission resources made by the Nevada Power Company and Sierra Pacific Power Company in their 2006 Integrated Resource Plan filings.
TEXAS OFFICE OF PUBLIC UTILITY COUNSEL 1701 N. Congress Ave., Suite 9-180 Austin, TX 78701- 512-936-7500 Mr. Clarence L. Johnson, Director, Regulatory Analysis (retired)	**ANALYZED REASONABLENESS OF EL PASO ELECTRIC COMPANY'S POWER PURCHASES. Feb 05 – Mar 06.** Reviewed and filed testimony regarding reasonableness of three contracts signed by El Paso Electric Company in 2001 for delivery of power in 2002.
UTILITY CONSUMERS' ACTION NETWORK 3100 5th Ave., Suite B San Diego, CA 92103 619-696-6966 Mr. Michael Shames, Executive Director (former)	**ANALYZED SAN DIEGO GAS & ELECTRIC PROPOSAL TO DEVELOP NEW POWER PLANTS. Sep 03 – Sep 06.** Review, analyze, and testify on SDG&E's plan to purchase Palomar power plant, contract for power from Otay Mesa power plant, and make other transactions. (*Joint effort with TURN.*)
PASADENA WATER AND POWER 150 S. Los Robles Ave., Suite 200 Pasadena, CA 91101 Contact Woodruff for reference.	**ESTIMATED HISTORIC GAS COSTS. Apr – May 03.** Reviewed, analyzed, and provided testimony to Federal Energy Regulatory Commission regarding the gas costs facing Pasadena Water and Power during the period from October 2000 to June 2001.
NORTHERN CALIFRONIA POWER AGENCY 180 Cirby Way Roseville, CA 95678 916-781-3636 Mr. Thomas S.W. Lee, Mgr, Portfolio Planning	**CONFIDENTIAL PROJECT. Feb – Apr 03.**
AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION (c/o LEGAL SERVICES OF NORTHERN CALIFORNIA) 515 – 12th Street Sacramento, CA 95814 916-551-2150 Mr. Colin Bailey, Attorney Mr. Stephen Goldberg, Attorney	**ANALYZED NEED FOR PROPOSED GAS STORAGE PROJECT. Dec 10 – Jan 11.** Reviewed, analyzed and testified on need for proposed Sacramento Natural Gas Storage Project.

ADDENDUM 2

to Resume of Kevin Woodruff

EXPERIENCE RELATED TO ELECTRIC RESOURCE PLANNING AND ASSET VALUATION

Woodruff Expert Services
Sacramento, California
November 2002 to present

- Analyze and provide expert testimony regarding cost-effectiveness of California Investor-Owned Utilities' (IOUs') specific proposals to contract for or acquire electric generating projects, both conventional and renewable.
- Analyzing alternatives for Entergy Arkansas, Inc. (EAI) to provide or procure electric system planning and operation services following its withdrawal from the Entergy System Agreement.
- Analyzing EAI proposal to allocate certain "wholesale baseload" resources to jurisdictional customers.
- Analyzing Puget Sound Energy proposal for "Coal Transition Power Purchase Agreement" (PPA) for output of TransAlta's Centralia coal plant.
- Analyzing proposal of Southwestern Electric Power Company and other owner to install environmental controls on coal-fired Flint Creek Power Plant.
- Analyzing California's electric Resource Adequacy Requirement and electric IOUs' long-term electric resource plans and short-term procurement and risk mitigation plans.
- Analyze and provide comments procurement and risk mitigation strategies as part of each California IOU's Procurement Review Group.
- Monitor development of estimates of renewable transmission and other integration costs in California.
- Analyzed proposals to restructure Entergy's transmission planning processes.
- Analyzed potential value of Algonquin Power Corporation's proposed Northern Maine Interconnect.
- Analyzed proposal of Avista to assign to Avista Utilities a PPA and related contracts related to the Lancaster (combined cycle) Generating Facility.
- Analyzed proposal of EAI and other owners to install scrubbers and low NOx burners at the coal-fired White Bluff Steam Electric Station.
- Led effort to assess value of San Diego Gas & Electric Company's proposed Sunrise Powerlink on behalf of Commission's Division of Ratepayer Advocates (DRA).
- Initiated analysis of cost-effectiveness of Maine Public Service and Central Maine Power Company's proposed Maine Power Connection transmission project.
- Analyzed proposal of EAI to purchase the Ouachita (combined cycle power) Plant.
- Led effort to assess value of Southern California Edison's proposed Devers-Palo Verde No. 2 Transmission Line Project (DPV2) on behalf of DRA.
- Led analysis of proposals to build significant new generation and transmission resources made by the Nevada Power Company and Sierra Pacific Power Company in their 2006 Resource Plan filings.
- Analyzed and provided analysis regarding California state agencies' initiatives to develop consistent process for planning for and evaluating new transmission projects.

Henwood Energy Services, Inc.
Sacramento, California
April 1988 to November 2002

- Modeled and analyzed long-term resource planning issues of California electric IOUs
- Modeled and analyzed short-term operations of California electric IOUs
- Prepared resource plan for municipal utility
- Managed and assisted public power entity's power supply Request for Proposal (RFP) processes
- Helped generation plant owners respond to California IOU and other RFPs for electric power
- Sold, conducted, and/or managed forecasts of power market operations and prices and related valuations of generating assets
- Prepared analyses of IOU and municipal utility revenue requirements, stranded costs, and rate design
- Managed projects to develop and implement software for electric plant and system operations, electric system forecasting and planning, risk quantification, and asset valuation
- Sold and managed projects to develop and implement maintenance planning software for vertically-integrated utilities
- Helped electric generators buy gas commodity and pipeline capacity rights
- Prepared and defended expert testimony on behalf of applicants and interveners in Commission proceedings in California and Montana

Sierra Energy and Risk Assessment
Sacramento / Roseville, California
May 1986 to April 1988 (full-time)
November 1985 to May 1986 (part-time)

- Assisted analysis for CPUC advocacy staff regarding SCE's proposed Devers-Palo Verde 2 transmission line.

ATTACHMENT 2

to Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

SCE's Response to 9th Question of TURN's 1st Data Request

Southern California Edison
2012 LTPP R.12-03-014

DATA REQUEST SET TURN-SCE-001

To: TURN
Prepared by: Daniel Donaldson
Title: Power Systems Planner
Dated: 09/03/2013

Question 09:

Data in both SCE's and SDG&E's testimony show that the allowance of load shedding in the San Diego local area to mitigate the "N-1-1" contingency will change reliability needs in the LA Basin and San Diego local areas, respectively (SCE, Table III-5 on p. 32; SDG&E August 26 Testimony, Jontry, 7:18-20 and comparison of Tables 1 and 2, pp. 10-11). Does SCE believe it reasonable that load shedding in the San Diego local area could simultaneously affect reliability requirements in both the LA Basin and San Diego local areas? Explain why or why not.

Response to Question 09:

It is reasonable to assume that load shedding in the San Diego local area could simultaneously affect reliability requirements in both the LA Basin and San Diego local areas. As described in p. 24 lines 11-17 of SCE's testimony, the "N-1-1" contingency in SDG&E re-routes power through SCE service territory thus impacting both local areas. This contingency can be mitigated by load shedding or generation located in SCE or SDG&E since either solution will reduce the amount of local load that needs to be served via the transmission system. The CAISO further adds that generation in the northern part of San Diego is more effective than adding it in LA Basin (Robert Sparks Testimony, p. 24 lines 2-3 indicating a "1.24 MW reduction in the LA Basin for every 1 MW of generation added to San Onofre switchyard.").

ATTACHMENT 3

to Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

SDG&E's Response to 15th Question of TURN's 1st Data Request

TURN DATA REQUEST
TURN-SDG&E-DR-01
SDG&E LTPP – TRACK 4 - R.12-03-014
SDG&E RESPONSE
DATE RECEIVED: SEPTEMBER 4, 2013
DATE RESPONDED: SEPTEMBER 17, 2013

15. Data in both SDG&E's and SCE's testimony show that the allowance of load shedding in the San Diego local area to mitigate the "N-1-1" contingency will change reliability needs in the San Diego and Western LA Basin local areas, respectively (SDG&E August 26 Testimony, Jontry, 7:18-20 and comparison of Tables 1 and 2, pp. 10-11; SCE August 26 Testimony, Table III-5 on p. 32). Does SDG&E believe it reasonable to assume that load shedding in the San Diego local area could simultaneously affect reliability requirements in both the San Diego and Western LA Basin local areas? Explain why or why not.

SDG&E Response 15:

Yes, under the all-generation scenario the reliance on the Safety Net to mitigate the N-1-1 contingency of SWPL and Sunrise reduces the amount of generation required in both the Western LA Basin and San Diego LCR areas.

ATTACHMENT 4

to Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

SCE's Response to 5th Question
of Energy Divisions 2nd Data Request

Southern California Edison
2012 LTPP R.12-03-014

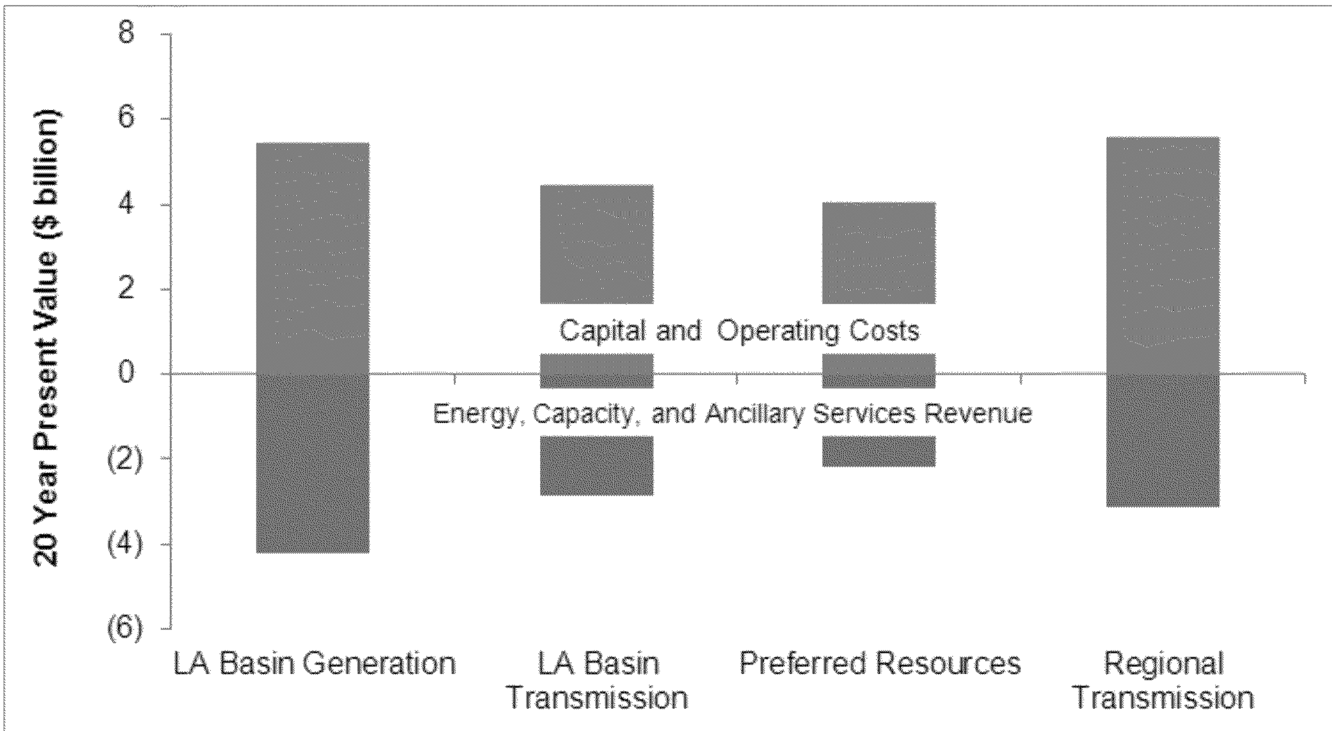
DATA REQUEST SET ED-SCE-002

To: ENERGY DIVISION
Prepared by: Justin Kubassek
Title: Senior Financial Analyst
Dated: 09/05/2013

Question Q.05:

Regarding Figure IV-7, the costs shown are the difference between the capital and operating costs on the one hand and the revenue from the sale of energy, capacity and ancillary services on the other hand (per explanation on Page 41). Please show these two components separately for each scenario.'

Response to Question Q.05:



20 Year PV $B	LA Basin Generation	LA Basin Transmission	Preferred Resources	Regional Transmission
Capital Cost	3.14	2.97	3.12	3.92
Operating Cost	2.32	1.50	0.93	1.68
Total Cost	*5.46*	*4.47*	*4.05*	*5.60*
Capacity, and Ancillary Service Revenue	(0.75)	(0.59)	(0.59)	(0.60)
Energy Revenue	(3.46)	(2.29)	(1.60)	(2.54)
Total Revenue	*(4.20)*	*(2.89)*	*(2.19)*	*(3.14)*
Net Cost	**1.25**	**1.59**	**1.86**	**2.46**

ATTACHMENT 5

to Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

SDG&E's Response to 14th Question of TURN's 1st Data Request

TURN DATA REQUEST
TURN-SDG&E-DR-01
SDG&E LTPP – TRACK 4 - R.12-03-014
SDG&E RESPONSE
DATE RECEIVED: SEPTEMBER 4, 2013
DATE RESPONDED: SEPTEMBER 17, 2013

14. Provide the following information about the "WECC-certified load shedding scheme" cited at Jontry, 7:1-3:
    a. Provide a copy of the cited "WECC-certified load shedding scheme".
    b. Describe how the load shedding scheme would be used in practice to mitigate the specific N-1-1 contingency, including which customers would be affected, how much notice such customers would have before their service would be interrupted, and how long such customers' service would be affected.

SDG&E Response 14:

a. The Path 44 South of SONGS Safety Net ("Safety Net") protects the system from the overlapping outage of the two-500kV lines between Imperial Valley and the San Diego load center (*i.e.* the Sunrise Powerlink and the Imperial Valley-Miguel sections of the Southwest Powerlink). The outage of these two lines may increase the flow on Path 44 above its safe operating point. To protect against this, the Safety Net will automatically shed SDG&E load, thereby reducing the Path 44 flow to a safe operating level. The Safety Net was designed consistent with the WECC Remedial Action Scheme Design Guide, and was approved by the WECC Remedial Action Scheme Reliability Subcommittee (RASRS) on November 28, 2012.[1] The objective of the NERC, WECC and CAISO reliability criteria is to ensure that systems are being developed to meet projected load. These criteria gage system performance following a contingency to measure the performance of the system in question. In particular, NERC standards TPL-003-0b2[2] and TPL-004-0a3[3] define acceptable performance levels for different categories of system events and as shown on Table I of the standards, load shedding is permitted to protect the system following the overlapping outage of two transmission lines. In brief, using the Safety Net to protect the system by shedding load is an appropriate tool for maintaining reliability and is consistent with the NERC, WECC and CAISO reliability requirements.

b. In practice, the Safety Net Special Protection Scheme ("SPS") would be armed when both the Southwest Powerlink and Sunrise Powerlink are both in service. The Safety Net monitors flow on the five Path 44 230 kV lines (South of SONGS). When the flow on the five lines exceeds a level determined to place the system at risk of voltage collapse, due to the loss of the Southwest Powerlink and the Sunrise Powerlink, the SPS would sequentially shed two blocks of approximately 500 MW of load in north

[1] The Safety Net was approved pending the results of a system study showing that the effects of inadvertent operation did not result in a condition worse than Category C. Draft minutes from the July 23, 2013 RASRS meeting document that system studies were presented which showed no issues with bus voltages following an inadvertent operation of the Safety Net. The Path 44 South of SONGS Safety Net was approved with no further discussion or objections by RASRS at that meeting.

[2] Table I, Category C3.

[3] Table I, Category D7.

Response to Question 14 (Continued)

San Diego County and southern Orange County, reducing the flow on Path 44 to a level sufficient to prevent voltage collapse. The load shedding could occur without notice and time to restore load would depend on system conditions. After the initial load shed, SDG&E can then move to rotational outages across the entire service territory and restore the customers initially affected. This approach allows SDG&E to selectively turn off power to circuits which do not serve hospitals, police stations, etc. until system conditions allow us to restore all customers.

ATTACHMENT 6

to Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

"Determining an Effective Mix of Non Conventional Solutions
to Address Local Needs in the TPP",
CAISO Presentation to 2013/2014 Transmission Planning
Process Stakeholder Meeting,
September 25, 2013

Determining an Effective Mix of Non Conventional Solutions to Address Local Needs in the TPP *

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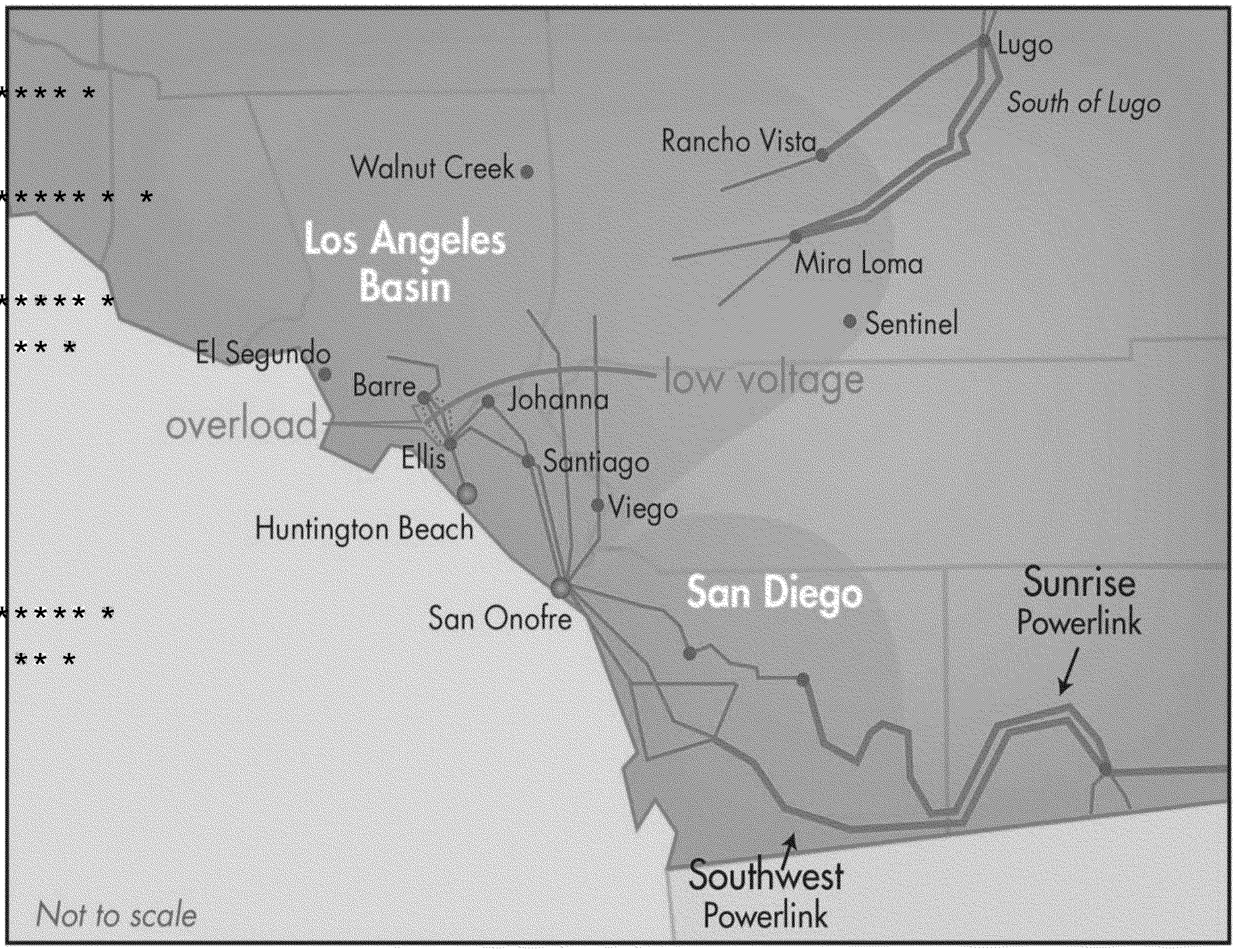

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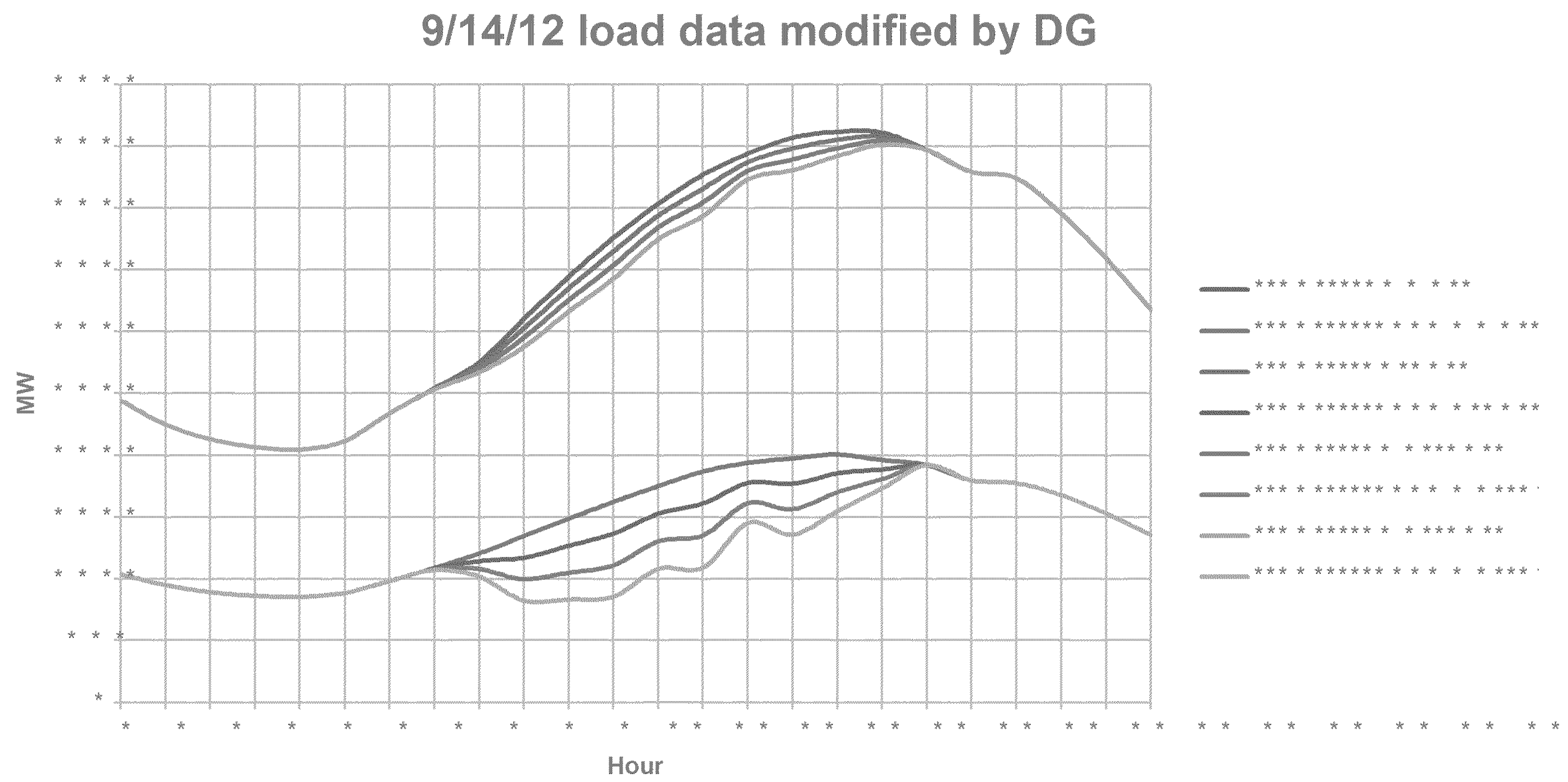

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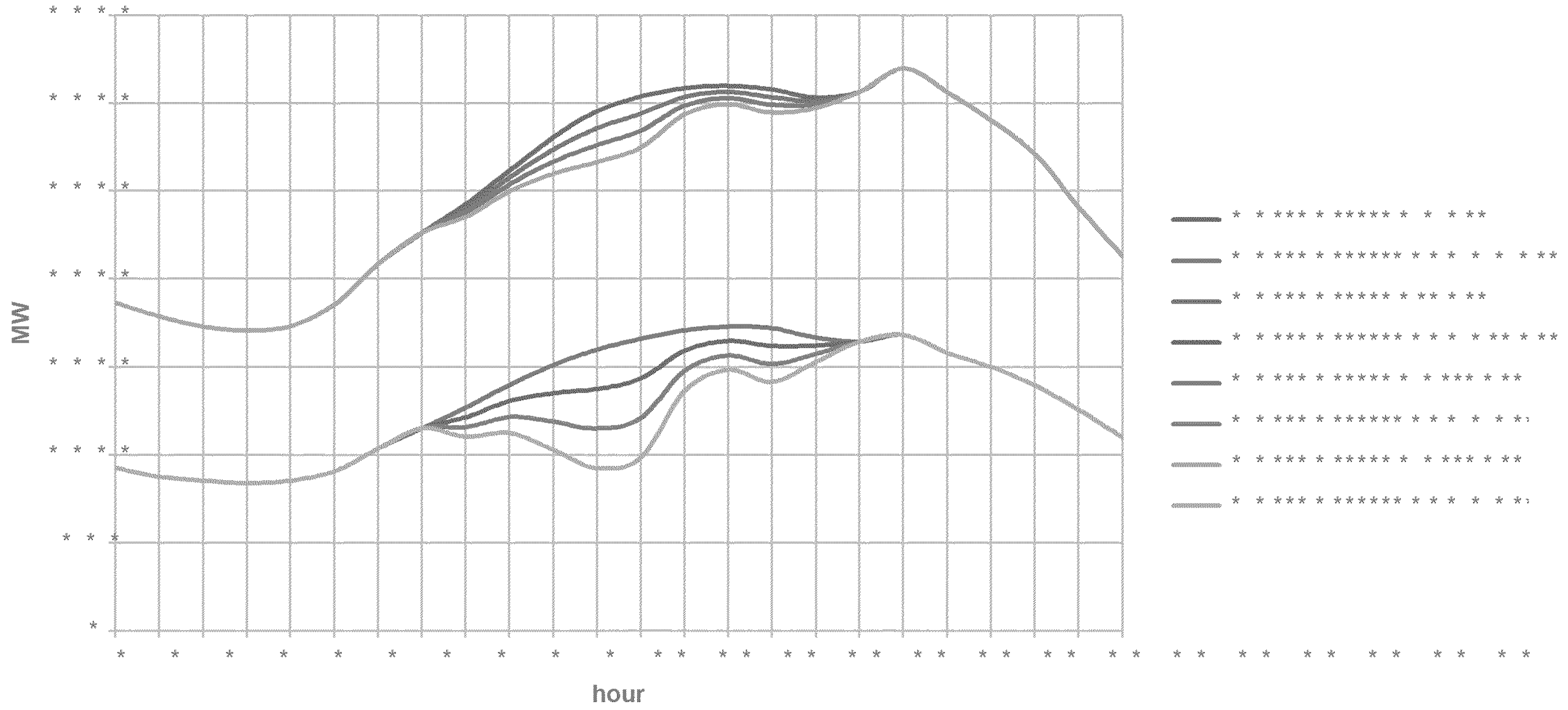
11/5/12 DG Modified load profile



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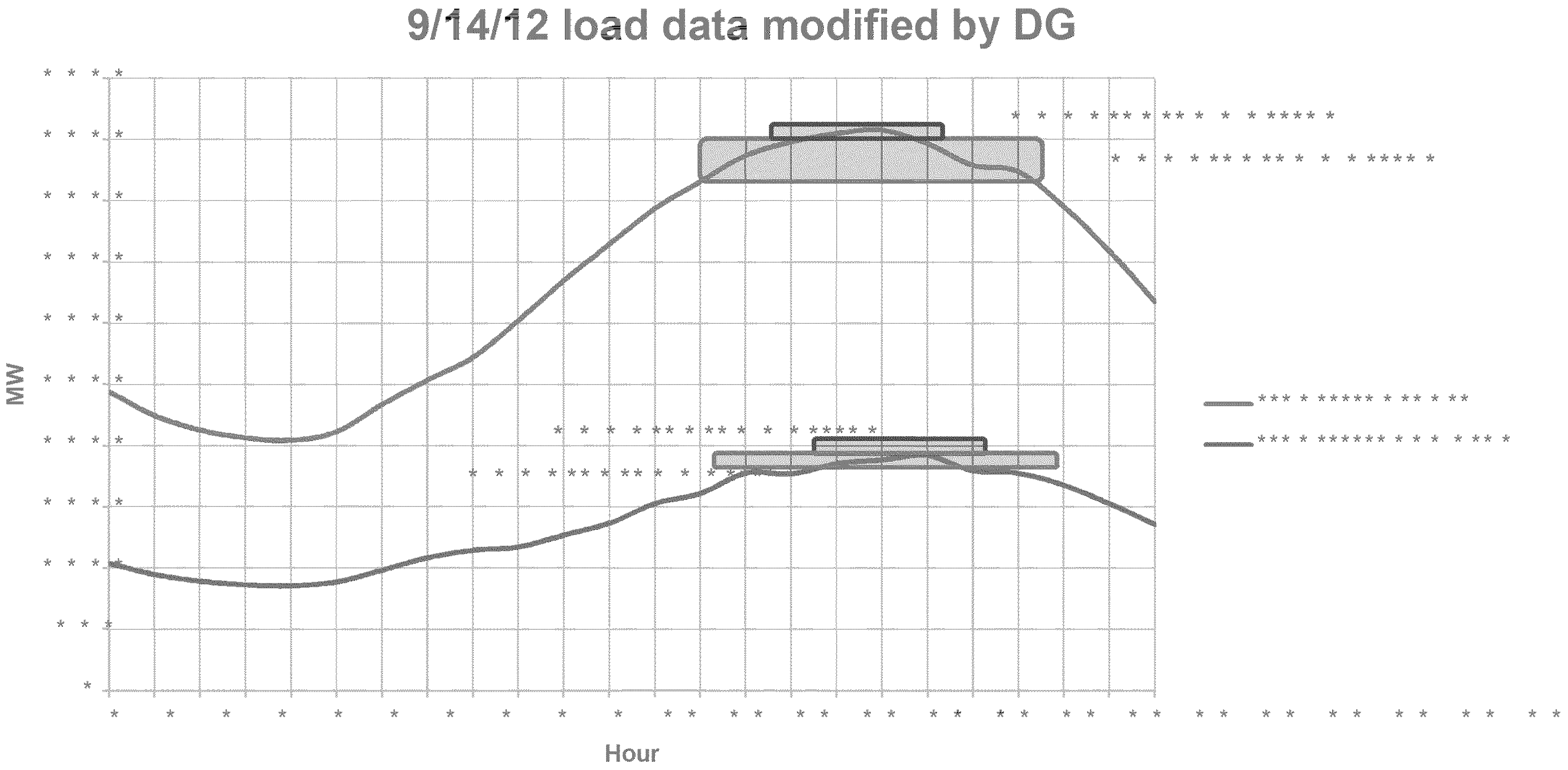

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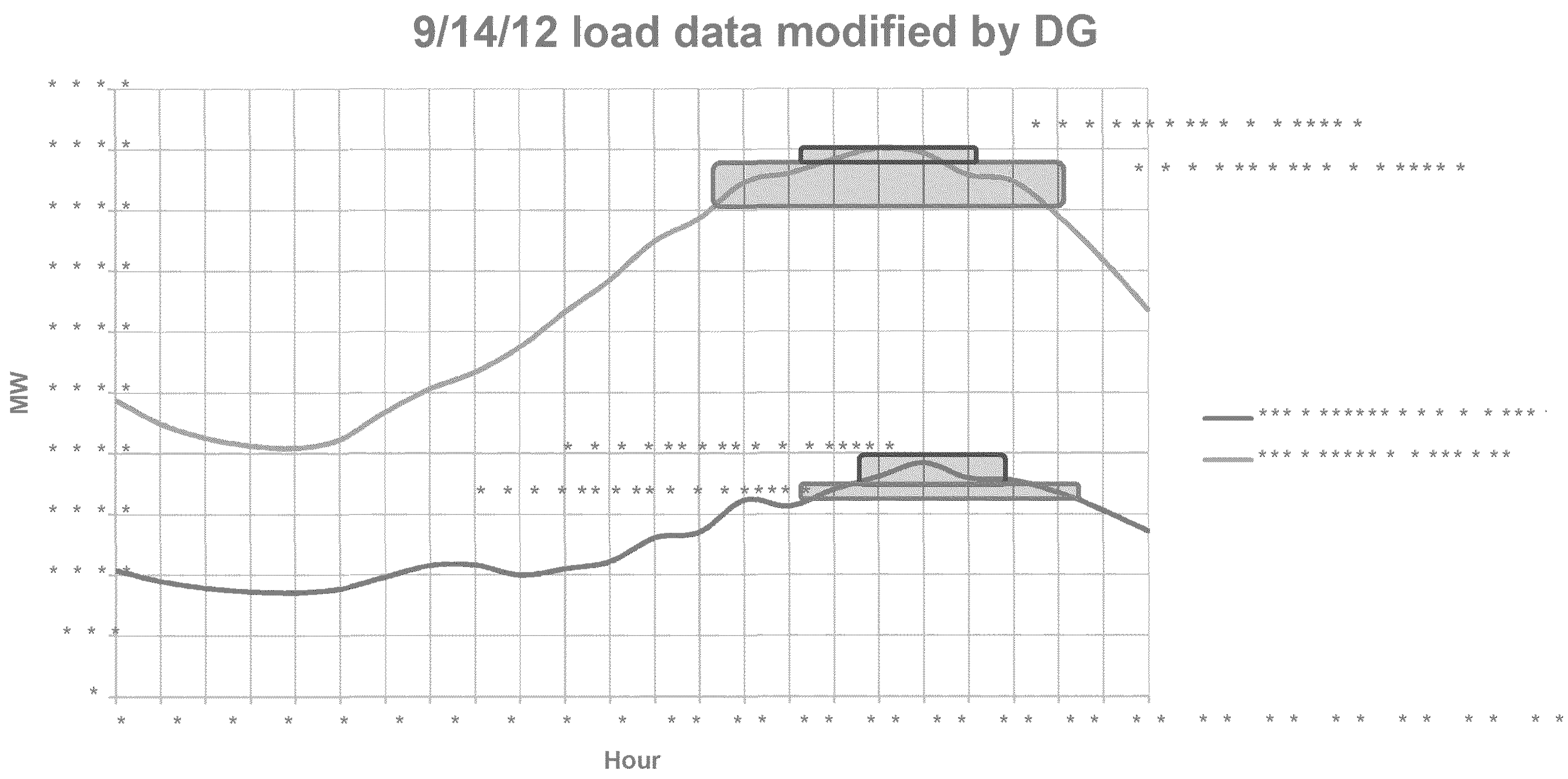
9/14/12 load data modified by DG
MW
Hour

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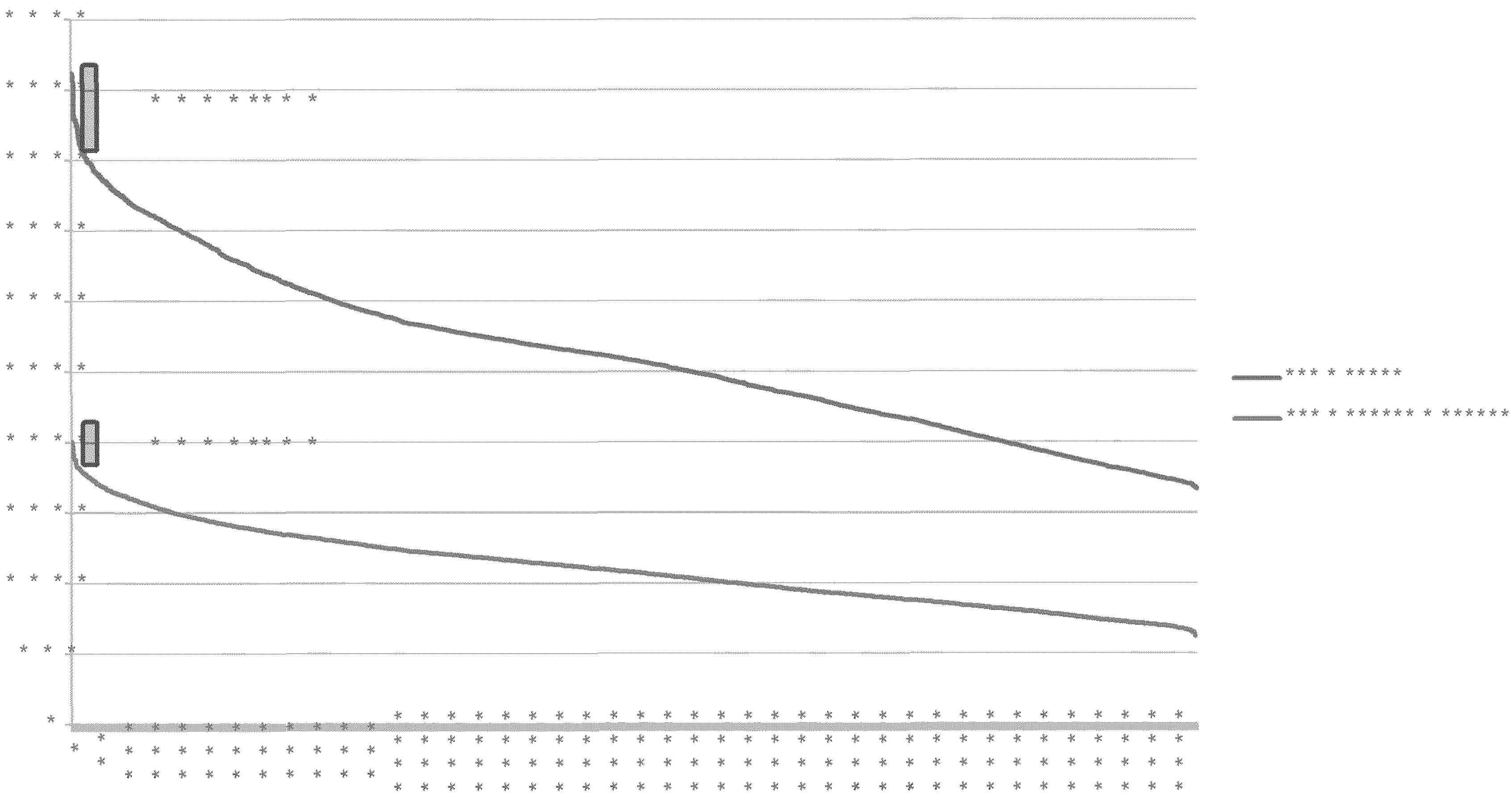

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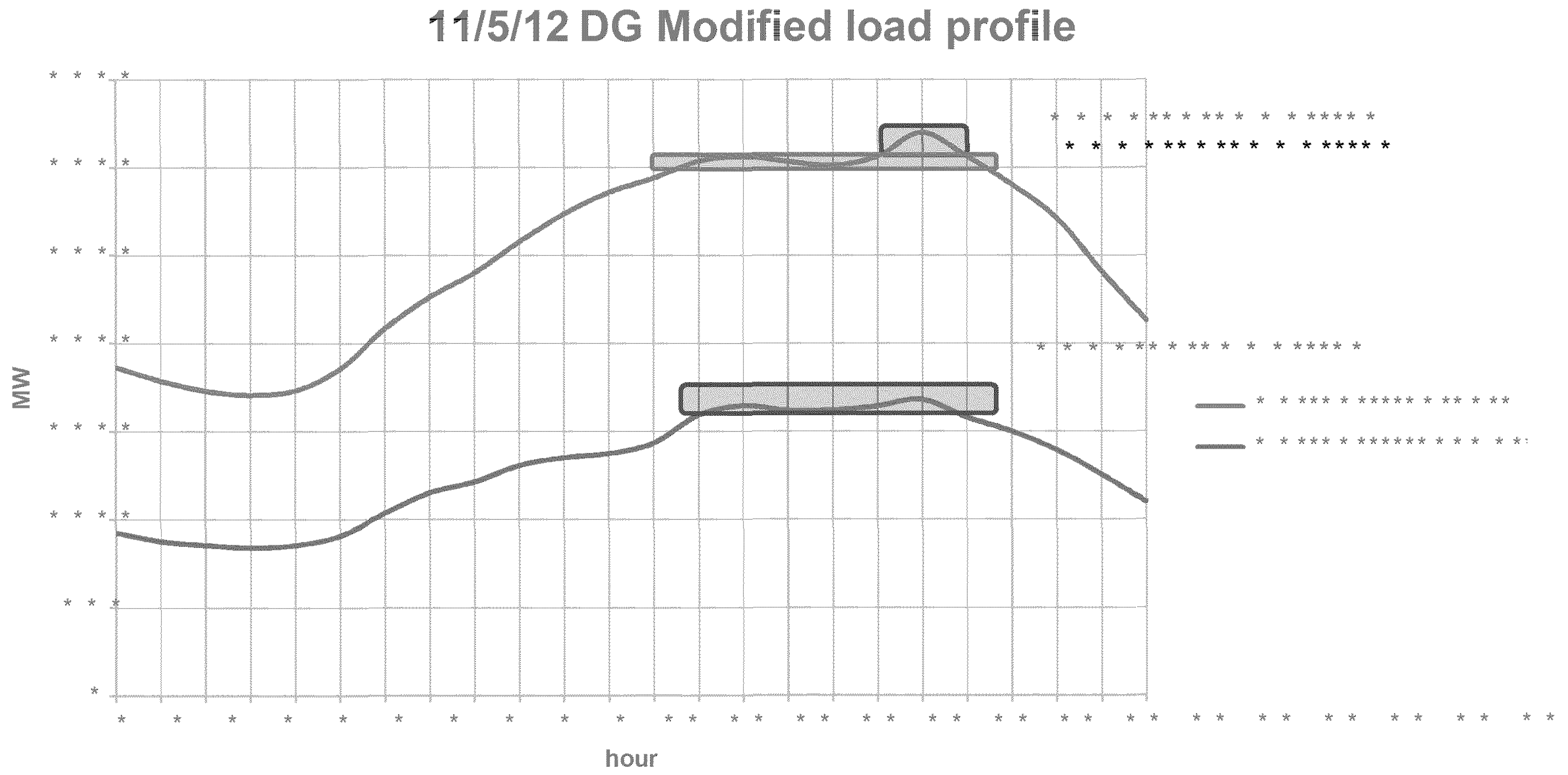

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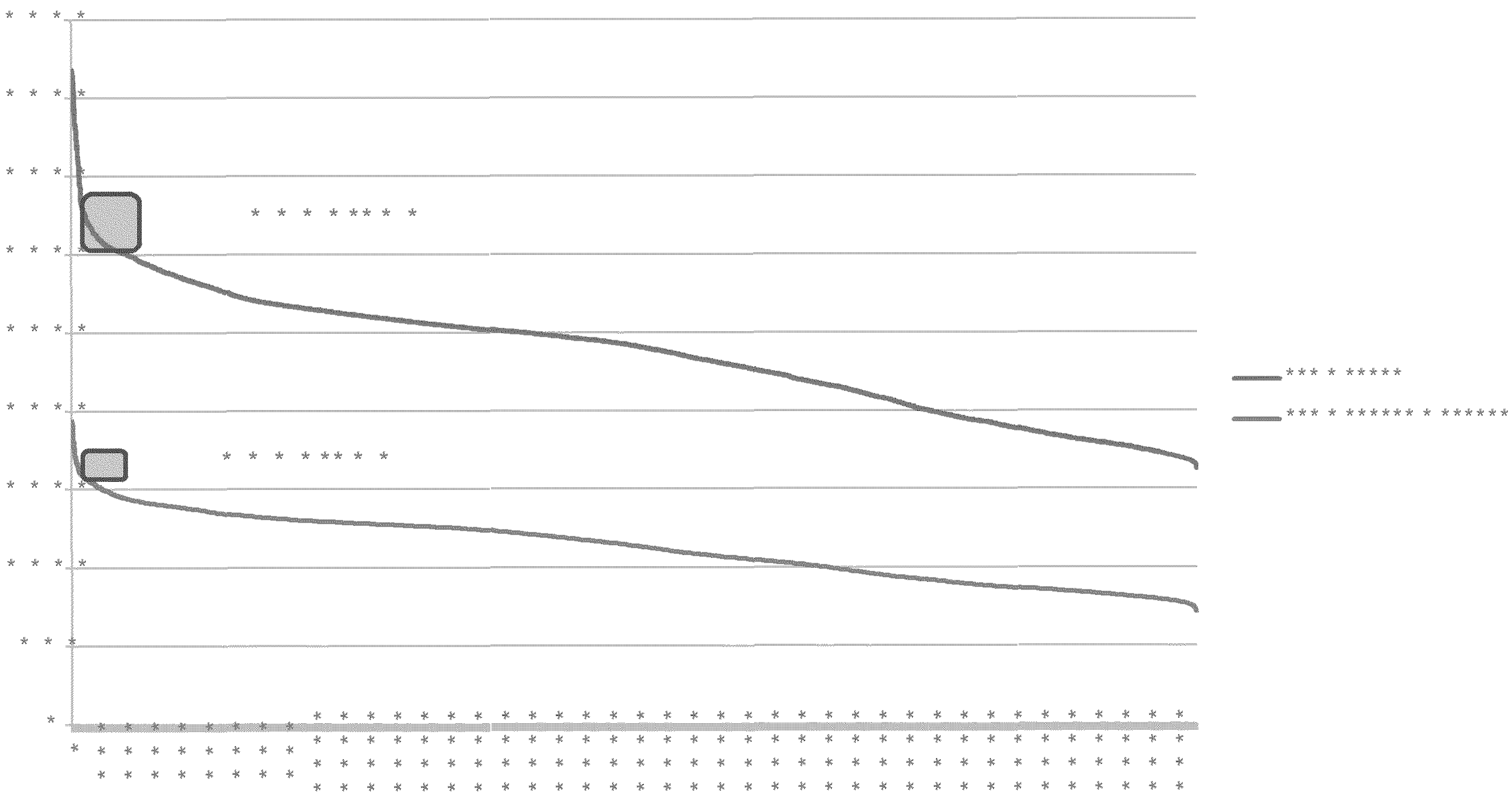

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APPENDIX A

to Direct Testimony of Kevin Woodruff on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

Documentation of CAISO's Option to Use Load Shedding as a Mitigation for N-1-1 Contingencies

Q. What is the purpose of this Appendix A to your Direct Testimony?

A. This Appendix provides information to help the Commission assess one of the key issues it should consider in resolving Track 4 of this docket: whether it should agree with the CAISO's discretionary decision to *not* allow load shedding as a means of mitigating the key contingency that drives the local capacity needs for the LA Basin and San Diego LRAs. That critical contingency is the "N-1-1" overlapping outage of the Sunrise Powerlink (Sunrise) and the Southwest Powerlink (SWPL).

Q. What information are you providing in this Appendix A?

A. In this Appendix, I provide five documents clearly documenting the discretionary nature of the decision to prohibit the use of load shedding to mitigate the key N-1-1 contingency. I also recommend the CAISO and Commission review and discuss this issue fully and publicly.

Q. What is the first document you are providing and what particular portion of that document merits the Commission's attention?

A. The first document, Attachment A-1, is Table 1 from the NERC's "Standard TPL-003-0b," which establishes allowable responses to the loss of two more elements of the Bulk Electric System. This document establishes the key N-1-1 contingency in this docket as a Category C.3 event, and specifies that demand may be curtailed for such an event on a planned or controlled basis.[1]

Q. What is the second document you are providing and what particular portion of that document merits the Commission's attention?

A. The second document, Attachment A-2, is Table 1 from the CAISO's *Final Manual* for *2014 Local Capacity Area Technical Study.*[2] This document also establishes the key N-

[1] The complete document is available at http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-003-0b.pdf.

[2] In response to Question 16a of the DRA's 1st Data Request, the CAISO specified that its Track 4 studies were being performed on the same basis as its LCR studies.

1-1 contingency in this docket as a Category C.3 event, and in footnote 7 specifies that demand may be curtailed for such an event on a planned or controlled basis.[3]

Q. What is the third document you are providing and what particular portion of that document merits the Commission's attention?

A. The third document, Attachment A-3, is pages 7 to 11 from the CAISO's *2014 Local Capacity Technical Analysis, Final Report and Study Results*. These pages discuss the CAISO's grid management standards more generally and include the paragraph:[4]

> Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security." (emphasis original)

Q. What is the fourth document you are providing and what particular portion of that document merits the Commission's attention?

A. The fourth document, Attachment A-4, is a "Major Issues Table" that was part of status report on the discussion of major issues by the "LCR Study Advisory Group" (LSAG) in late 2006.[5,6] Issue 4 reflects the CAISO belief that a "consensus" was reached that "[c]ommensurate with NERC/WECC standards, there is consensus that load cannot be

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3 The complete document is available at http://www.caiso.com/Documents/2014LocalCapacityRequirementsFinalStudyManual.pdf. Similar or identical tables and notes have consistently been included in prior manuals.

4 See page 10. The complete document is available at http://www.caiso.com/Documents/Final2014LocalCapacityTechnicalStudyReportApr30_2013.pdf. Similar or identical discussions have consistently been included in prior studies.

5 This document is available at http://www.caiso.com/Documents/MajorIssues-LSAGMeeting06-Nov-2006.pdf.

6 The LSAG was convened to help parties – including the utilities, generators and other parties – review in detail the reliability criteria the CAISO proposed to use to set LCRs. I participated in the LSAG on behalf of TURN. LSAG documents are available at http://www.caiso.com/Documents/Local%20capacity%20requirements%20process%20archive.

dropped after a single contingency and that load can be dropped in a 'planned and controlled' manner after the second contingency".

Q. What is the fifth document you are providing and what particular portion of that document merits the Commission's attention?

A. The fifth document, Attachment A-5, is an excerpt from a presentation CAISO staff made to summarize the results of the LSAG process. Slide 11 of that presentation presents a chart showing that "planned and controlled load shedding" is permissible for N-1-1 contingencies.[7,8]

Q. The CAISO has already acknowledged that it is able to consider load shedding as mitigation for the key N-1-1 contingency. Why are you providing these additional documents on this issue?

A. I have two reasons for providing such documents. First, I want the Commission to have a record on this issue that is reasonably complete and unambiguous.

Second, I want to highlight that the CAISO has engaged in significant public communication and discussion about the nature of its local reliability criteria for several years, including the fact that it has discretion to recognize load shedding schemes to mitigate N-1-1 contingencies. However, the CAISO's exercise of its discretion on the issue of load shedding to mitigate a combined Sunrise / SWPL outage has – despite the cost implications for customers – apparently been conducted at a staff level with little or no public discussion. The Commission should consider this matter openly in this and possibly future dockets and encourage the CAISO to review this issue in a more public manner as well.

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7 This same chart has consistently appeared in the CAISO's annual LCR studies. See Attachment A-3.

8 This complete document is available at http://www.caiso.com/Documents/Presentation-LCRStudyAdvisoryGroup06-Dec-2006.pdf.

ATTACHMENT A-1

to Appendix A of Direct Testimony of Kevin Woodruff
on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

Table 1
North American Electric Reliability Corporation Standard TPL-003-0b, "System Disturbance Following Loss of Two or More BES Elements"

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:			
	1. Generator	Yes	No[b]	No
	2. Transmission Circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
	Loss of an Element without a Fault.	Yes	No[b]	No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section	Yes	Planned/ Controlled[c]	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[f]	Yes	Planned/ Controlled[c]	No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission Circuit	Yes	Planned/ Controlled[c]	No
	9. Bus Section	Yes	Planned/ Controlled[c]	No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. * May involve substantial loss of customer Demand and generation in a widespread area or areas. * Portions or all of the interconnected systems may or may not achieve a new, stable operating point. * Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b)Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d)A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

ATTACHMENT A-2

to Appendix A of Direct Testimony of Kevin Woodruff
on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

Table 1
Final Manual, 2014 Local Capacity Area Technical Study
CAISO, January 2013

California ISO
Shaping a Renewed Future

Final Manual

2014 Local Capacity Area Technical Study

January 2013

Version

Prepared by:

California Independent System Operator

Table 1: Criteria Comparison

Contingency Component(s)	*Grid Planning*	*Local Capacity*
A – No Contingencies	X	X
B – Loss of a single element		
1. Generator (G-1)	X[1]	X[1]
2. Transmission Circuit (L-1)	X[1]	X[1]
3. Transformer (T-1)	X[1]	X[1,2]
4. Single Pole (dc) Line	X[1]	X[1]
5. G-1 system readjusted L-1	X	X
C – Loss of two or more elements		
1. Bus Section	X	
2. Breaker (failure or internal fault)	X	
3. L-1 system readjusted G-1	X	X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X	X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X	X
3. G-1 system readjusted G-1	X	X
3. L-1 system readjusted L-1	X	X
3. T-1 system readjusted T-1	X	
4. Bipolar (dc) Line	X	X
5. Two circuits (Common Mode) L-2	X	X
6. SLG fault (stuck breaker or protection failure) for G-1	X	
7. SLG fault (stuck breaker or protection failure) for L-1	X	
8. SLG fault (stuck breaker or protection failure) for T-1	X	
9. SLG fault (stuck breaker or protection failure) for Bus section	X	
WECC-S3. Two generators (Common Mode) G-2	X[3]	X
D – Extreme event – loss of two or more elements		
Any B1-4 system readjusted (Common Mode) L-2	X[4]	X[3]
All other extreme combinations D1-14.	X[4]	

1 System must be able to readjust and support the loss of the next element within A/R.

2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

4 Evaluate for risks and consequence, per NERC standards.

A significant number of simulations were run to determine the most critical contingencies within each local area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all tested contingencies were measured against the system performance requirements defined by the criteria shown in Table 1. Where the specific system performance requirements were not met, generation was adjusted until performance requirements were met for the local area. The adjusted generation constitutes the minimum generation needed in the local area. The following describes how the criteria were tested for the specific type of analysis performed.

1. *Power Flow Assessment:*

Contingencies	Thermal Criteria[3]	Voltage Criteria[4]
Generating unit [1, 6]	Applicable Rating	Applicable Rating
Transmission line [1, 6]	Applicable Rating	Applicable Rating
Transformer [1, 6]	Applicable Rating[5]	Applicable Rating[5]
(G-1)(L-1) [2, 6]	Applicable Rating	Applicable Rating
Overlapping [6, 7]	Applicable Rating	Applicable Rating

[1] All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on Participating Transmission Owners' local area systems.

[2] Most severe generating unit out, system readjusted, followed by a line outage. This over-lapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

[3] Applicable Rating – Based on ISO Transmission Register or facility upgrade plans including all established path ratings.

[4] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

[5] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[6] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions and be able to safely prepare for the loss of the next most stringent element and be within Applicable Rating after the loss of the second element.

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. *Post Transient Flow Assessment:*

Contingencies	Reactive Margin Criteria [2]
Selected [1]	Applicable Rating

ATTACHMENT A-3

to Appendix A of Direct Testimony of Kevin Woodruff
on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

Excerpt
2014 Local Capacity Technical Analysis,
Final Report and Study Results
CAISO, April 30, 2013

2014
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2013

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the Reliability Standards of the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council ("WECC") Regional Criteria (collectively "Reliability Standards"). The Reliability Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the Reliability Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the Reliability Standards.[3] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the Reliability Standards as well as reliability criteria adopted by the CAISO (Grid Planning Standards).

The Reliability Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The Reliability Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

[3] Pub. Utilities Code § 345

D. Application of N-1, N-1-1, and N-2 Criteria

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions Category A (N-0) the CAISO must protect for all single contingencies Category B (N-1) and common mode Category C5 (N-2) double line outages. Also, after a single contingency, the CAISO must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as requirement R1.1 of the WECC Regional Criteria[3] ("two adjacent circuits") with no manual system adjustment between the two contingencies.

E. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCT Report is based on NERC performance level B and performance level C standard. The NERC Standards refer mainly to system being stable and both thermal and voltage limits be within applicable ratings. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC regional criteria that further specifies the dynamic and reactive margin requirements for the same NERC performance levels. These performance levels can be described as follows:

a. LCR Performance Criteria- Category B

Category B describes the system performance that is expected immediately following the loss of a single transmission element, such as a transmission circuit, a generator, or a transformer.

Category B system performance requires that system is stable and all thermal and voltage limits must be within their "Applicable Rating," which, in this case, are the emergency ratings as generally determined by the PTO or facility owner. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met; however there is no guarantee that facilities are returned to within normal ratings or to a state where it is safe to continue to operate the system in a reliable manner such that the next element out will not cause a violation of the Applicable Ratings.

b. LCR Performance Criteria- Category C

The Reliability Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[4] All Category C requirements in this report refer to situations when in real time

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[4] A Special Protection Scheme is typically proposed as an operational solution that does not require

(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing Reliability Standards.

Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

c. CAISO Statutory Obligation Regarding Safe Operation

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Standards at all times, for example during normal operating conditions Category **A (N-0)** the CAISO must protect for all single contingencies Category **B (N-1)** and common mode Category **C5 (N-2)** double line outages. As a further example, after a single contingency the CAISO must readjust the system in order to be able to support the loss of the next most stringent contingency Category **C3 (N-1-1)**.

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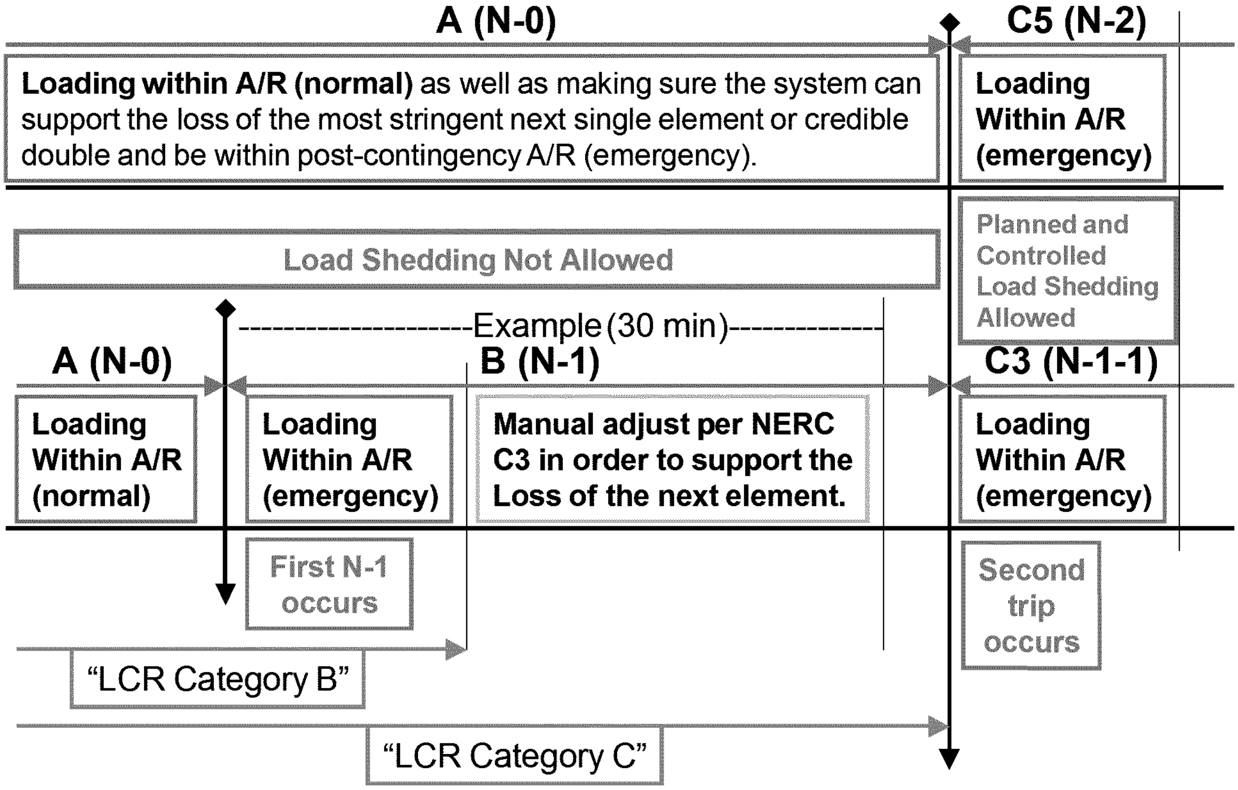
additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.

Figure 1: Temporal graph of LCR Category B vs. LCR Category C:



The following definitions guide the CAISO's interpretation of the Reliability Standards governing safe mode operation and are used in this LCT Study:

Applicable Rating:

This represents the equipment rating that will be used under certain contingency conditions.

Normal rating is to be used under normal conditions.

Long-term emergency ratings, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

Short-term emergency ratings, if available, can be used as long as "system

ATTACHMENT A-4

to Appendix A of Direct Testimony of Kevin Woodruff
on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

"Major Issues Table, LCR Study Advisory Group (LSAG)" CAISO, November 6, 2006

Major Issues Table
LCR Study Advisory Group (LSAG)
November 6, ISO Offices in Folsom

Issues: LSAG Will Address – Technical Related		
Issue	**Result**	**Discussion**
1. Technically understand the methodology applied by the CAISO's in the 2007 LCR Study	Consensus achieved	Majority of LSAG members agree that the CAISO 2007 LCR results correctly reflect the methodology and criteria described in the 2007 LCR Study. Study assumptions, base cases, transmission configuration, and methodology were fixed through the CPUC's "Meet and Confer Workshop. CAISO has explained how it applied the NERC/WECC standards to the study results. Consensus has been reached that the CAISO is an independent party and has the required expertise and best available data in order to run these types of studies for future years.
2. Deliverability of Imports	Majority agreement achieved	Methodology used in the CAISO's 2007 LCR analysis is consistent with current Deliverability assessment. This methodology protects the deliverability (under normal and contingency category B and C5 only) of total import allocations on each branch group deemed deliverable through the "deliverability studies" to facilitate long-term contracts, and their import must be deliverable to the aggregate of load. The majority agreed that the same assumption should be used for the 2008 LCR studies.
3. Deliverability of Generators	Majority agreement achieved	Methodology used in the CAISO's 2007 LCR analysis is consistent with current Deliverability assessment. This methodology protects the deliverability (under normal and contingency category B and C5 only) of all existing generator deemed deliverable through the "deliverability studies" to facilitate long-term contracts, and their output must be deliverable to the aggregate of load. The majority agreed that the same assumption should be used for the 2008 LCR studies.
4. Clarifying NERC/WECC Category B and C Performance Standards	Consensus achieved	Commensurate with NERC/WECC standards, there is consensus that load cannot be dropped after a single contingency and that load can be dropped in a "planned and controlled" manner after the second contingency. If there is NO controlled solution (SPS or operating procedure with short term emergency ratings) of dropping load after the second contingency the CAISO is required to dispatch generation or drop load before the second contingency (effectively at a short time after a single contingency, through system readjustment) in an N-1-1 case and (under normal conditions) in an N-2 (common mode) case in order to make sure all system elements are within Applicable Ratings immediately following the second contingency. "System readjustment" is to be used after any single contingency and include operating procedures as well as generation reduction. Consensus has been reached in the interpretation of the performance standards and their application to the 2008 LCR studies.

5. Clarify that LSAG is a technical group and not a "stakeholder" process	Done	The LSAG is intended to resolve, or at least narrow the scope of disagreements regarding, technical issues related to the conduct of LCR studies for the benefit of all stakeholders and other decision-makers (such as CAISO management and the CPUC). The LSAG is not intended to resolve broader policy issues. CAISO has scheduled a stakeholder meeting on December 6, 2006 in order to get stakeholder involvement on LCR issues and define next steps.
6. Clarify what the "next steps" beyond the LSAG will be	TBD	As part of the LSAG work, the CAISO intends to "map" LCR objectives through 2009. CAISO will seek guidance from LSAG on what information to "map". This information will be pushed out to the stakeholders via Market Notice.
7. Transparency of Operating Procedures	Consensus achieved	The current process is: PTO proposes, CAISO validates and PTO/CAISO implements. The ISO will provide the operating procedures in an easy to interpret language that will allow parties to model its effect correctly. The ISO will provide starting base case – tuned for the local area before the generation is moved around. These steps will enable parties with modeling capability to validate operating procedures.
8. Definition of Load Pockets	Consensus achieved	The CAISO has developed a methodology for defining load pockets, based on historical patterns, fairly stable across years, which should facilitate long-term contracts for local resources. Consensus has been reached that the same assumption should be used for the 2008 LCR studies.
9. Appropriate 1 in 10 adverse weather load forecast	Consensus achieved	ISO will use the latest adopted load forecast. In any case the ISO will need the updated load forecast by January 2007. PTOs need time to spread a CEC system and zonal load forecast into a local (bus-bar) forecast before it can be released to the ISO for the 2008 LCR studies.
10. Option 1 or Option 2	ISO Tariff and NERC compliance	CAISO has an obligation to assure compliance with its Tariff as well as NERC standards. Requirements based on Option 2 go a long way into meeting this mandate given that the minimum required resources would be fully available at summer peak time. As Option 1 ignores Category C contingency it cannot be used to show compliance.
11. Zonal Requirements	TBD	Detailed discussion about the ISO proposed methodology or any new methodology has not been achieved mainly due to time constraints. There was acknowledgement that these needs exist and need to be addressed in the near future. CPUC intends to take this issue up in the next phase of RA discussions and efforts to frame this issue for CPUC are appropriate. For the 2008 LCR study, ISO will continue to publish the zonal requirement to meet the CPUC's requirement based on ISO's methodology.
12. Seasonal Studies	TBD	• Units under Local RA obligation are assumed to need to recover 100% of their fixed costs through contracts in order to be available to serve peak load next summer. Should they be required to be available 100 % of the time? Is there a need, savings, risks and rewards in letting units be unavailable part of the year (other times then the approved ISO must offer waiver denial)? • Monthly or seasonal studies will also need to take into account generation and transmission maintenance, generation emission restrictions, and clearance scenarios. If those scenarios are not

		taken into account, the technical study will not be meaningful, and just reflect the impact of lower loads using the same methodology. This issue will be discussed in stakeholder meeting. □ Answers to three questions can resolve this issue: 1. How will the CAISO adjudicate the waivers from "must offer requirements"? , 2. How should ESPs trade capacity during load migration for local RA – maybe in the same way they trade system RA? and/or 3. How to prepare a proper transmission model to reflect frequent transmission and generation maintenance schedules in non-summer months?
Issues: LSAG Will Not Address – Policy Related		
1. Load Forecast	TBD	The ISO will continue to use a 1 in 10 local load forecast as required per CAISO grid planning standards. This will give decision makers the opportunity to choose transmission projects, generation or demand side alternatives on the same footing level. Parties may revisit the 1 in 10 vs. 1 in 5 load forecast. Question: should this be addressed in 2008 Study?
2. Expansion of Local Area with New Transmission Infrastructure	TBD	New transmission infrastructure usually decreases the need in one area, for the same given boundary. When the new infrastructure changes the boundary of the local area then the project should be carefully considered. An example is that a project may not reduce the LCR requirement; however it could open the area up for increased competition (going from 100% of local generation to 80% of new local generation being needed). This is clearly in the benefit of the ratepayer; or else the project will most likely not get approved. Not withstanding the above, the technical considerations of defining load pockets are appropriate for LSAG to address.
3. New methodology	Objective moved to 2008 timeframe	□ Probabilistic methods - LOLP □ Discussion of alternative "methodologies" for determining LCR. Alternatives can be discussed across a longer term time period.
4. How much load shedding is allowed?	Objective moved to 2008 timeframe	Discuss in Grid Planning Standard committee
5. Allocation of LCR to non-jurisdictional entities	TBD	ISO is proposing to use the same methodology as in 2007. (CEC performed allocation in 2007.)
6. Aggregation of LCR areas	TBD	Combine requirements for different Local Areas what is the best approach going forward. From all showings, it seems that it worked for 2007 purchases.

ATTACHMENT A-5

to Appendix A of Direct Testimony of Kevin Woodruff
on behalf of The Utility Reform Network
in Track 4 of CPUC Rulemaking 12-03-014, September 30, 2013

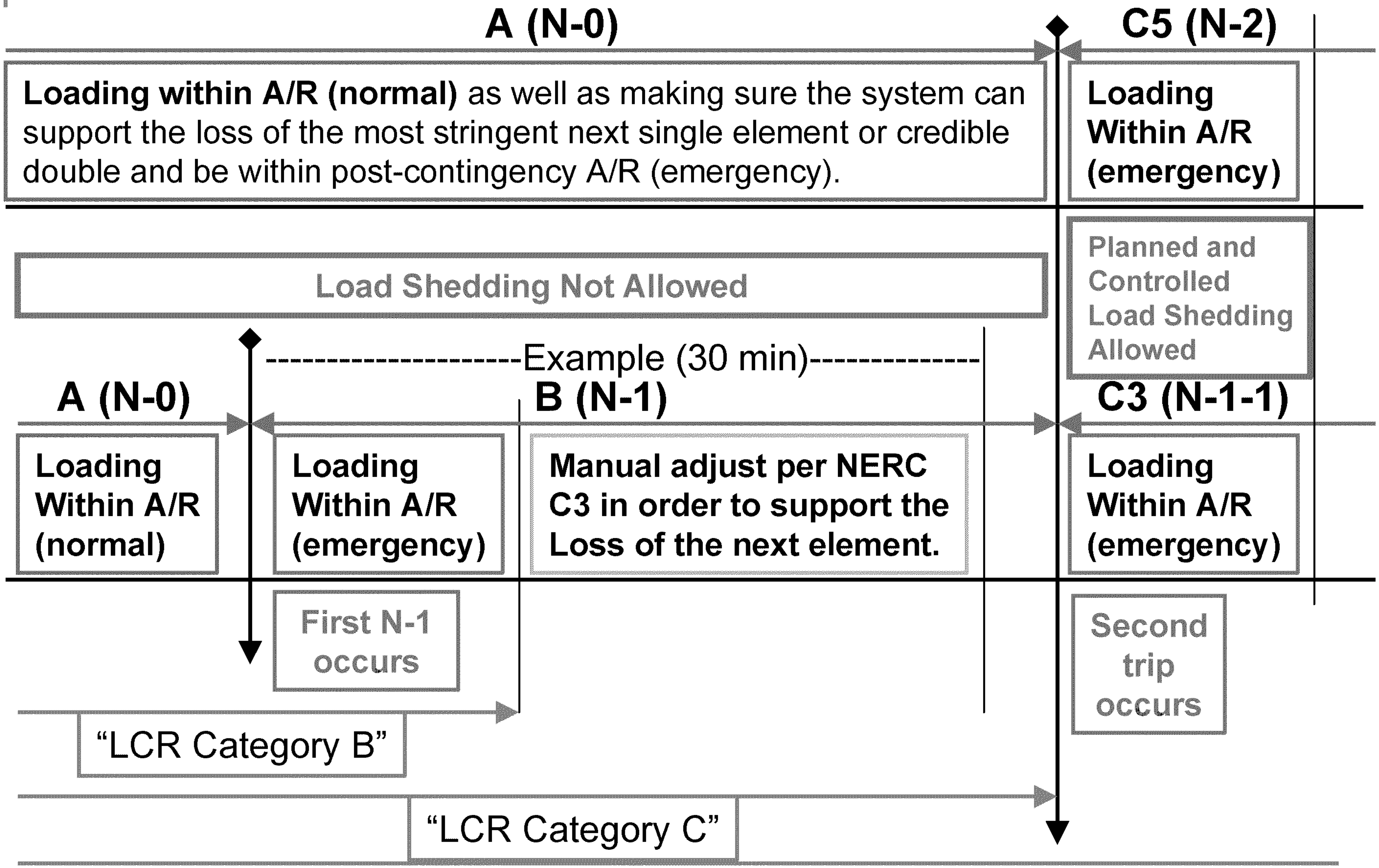
"LCR Study Advisory Group:
CAISO Standards including NERC&WECC Standards"
CAISO, December 6, 2006

LCR Study Advisory Group:
CAISO Standards including NERC & WECC Standards

CAISO Stakeholder Meeting
December 6, 2006

Catalin Micsa – Representing LSAG

Minimum Local Capacity Requirements



Terms

* A (N-0) normal system conditions; use normal ratings
* C5 (N-2) common mode (same tower or right-of-way); use emergency ratings
* B (N-1) single contingency conditions; use emergency ratings
* Manual Adjustment – any adjustment done by operators (other then load drop) in order to assure that the system is in a safe operating zone and can support the loss of the next most stringent single contingency
* C3 (N-1-1) double contingency conditions (specifically a single (B) followed by manual readjustment and then another single contingency (B); use emergency ratings
* Planned load drop means that the most limiting equipment has a higher short-term emergency rating (example - 30 min.) AND the operators have a operating procedure that clearly describes the actions needed to be taken in order to shed load
* Controlled load drop means the use of an Special Protection Scheme