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)

OPENING BRIEF OF GENON ENERGY, INC. ON TRACK 1 LOCAL RELIABLITY ISSUES

Lisa A. Cottle
Winston & Strawn LLP
101 California Street, Suite 3900
San Francisco, California 94111
Telephone: 415-591-1579
Facsimile: 415-591-1400
lcottle@winston.com

Attorneys for GenOn Energy, Inc.

September 24, 2012

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)

OPENING BRIEF OF GENON ENERGY, INC. ON TRACK 1 LOCAL RELIABLITY ISSUES

Pursuant to the Rule 13.11 of the Commission's Rules of Practice and Procedure and the schedule established by the Administrative Law Judge ("ALJ"), GenOn Energy, Inc. ("GenOn") submits its opening brief on Track 1 local reliability issues.

I.

EXECUTIVE SUMMARY

The time to act is now to ensure that the Big Creek/Ventura local reliability area will have sufficient capacity after 2020. The California Independent System Operator ("CAISO" or "ISO") has studied the issue thoroughly and determined that only 430 megawatts of capacity are needed to replace more than 2,000 megawatts of capacity in Big Creek/Ventura that are expected to retire by 2020 to comply with the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling ("OTC Policy"), as required by the California State Water Resources Control Board ("Water Board").

Why must the Commission act now? Any new generation project, regardless of its location in California, will take at least seven years to reach commercial operation. Even if the Commission orders procurement to begin by first quarter 2013, developers of replacement generation will have barely enough time to pursue procurement processes and achieve commercial operation by the deadlines in the OTC Policy. Delaying to the next long-term procurement plan proceeding ("LTPP") to decide the fate of Big Creek/Ventura, as some parties have advocated, all but ensures that the State will not satisfy the OTC Policy without jeopardizing grid reliability. The Commission should take action now to comply with the OTC Policy, while at the same time preserving grid reliability. The Commission should do this by directing Southern California Edison Company ("SCE") to procure a minimum of 430 megawatts of new capacity in Big Creek/Ventura. And it should do so at the earliest possible opportunity.

At the ALJ's direction, this brief incorporates the common briefing outline formulated by SCE with input from the parties. GenOn does not brief every issue in the outline, but includes those sections where no briefing is provided to preserve the outline's integrity.

II.

DETERMINATION OF LOCAL CAPACITY REQUIREMENTS (LCR) NEED IN CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) STUDIES

The CAISO's OTC study shows a need for 430 megawatts of capacity in the Moorpark subarea of Big/Creek Ventura to replace more than 2,000 megawatts of existing OTC capacity in Big Creek/Ventura that are expected to retire by 2020 to comply with the OTC Policy. The CAISO determined that 430 megawatts of capacity are needed in each of the four renewable portfolio scenarios that it studied.[1] The CAISO study was specifically designed "to identify areas within the ISO controlled grid that have local reliability needs and to determine the **minimum generation capacity** that would be required to satisfy these local reliability requirements."[2] The ISO used a methodology consistent with NERC planning standards requiring the use of contingency analyses.[3] Based on the study results, the CAISO recommends the long-term procurement of 430 megawatts of replacement capacity in the Moorpark subarea

---

1 Exhibit ISO-1 (Sparks Direct), p. 6, lines 1-6 and p. 14, lines 4-8 ("Approximately 430 MW of replacement OTC capacity is required across all four RPS portfolios to mitigate reliability issues in the Moorpark sub-area. This replacement OTC capacity is counted towards the total LCR need for the overall Big Creek/Ventura area.")

2 Exhibit ISO-6 (Millar Reply), p. 3, lines 3-6 (emphasis added).

3 Exhibit ISO-3 (Sparks Reply), p. 3, lines 1-3; Exhibit ISO-6 (Millar Reply), p. 3, lines 22-29.

of Big/Creek Ventura "to ensure the continued reliable operation of the ISO transmission system."[4]

In prior LTPP cycles when the Commission authorized procurement of new capacity, the Commission relied primarily on showings by the investor-owned utilities ("IOUs") of the need for new generation in their service areas. Track 1 of this LTPP presents a different dynamic. Two of the IOUs are not advocating a need determination in their service areas.[5] For SCE, the CAISO is sponsoring the evidence demonstrating a need in the SCE service area upon which a Commission decision must be based.

The Commission should give greater deference to the CAISO's recommendations for long-term procurement than that typically afforded to the recommendations of utilities or other self-interested parties. The CAISO's avowed interests lie in ensuring that the electric system has adequate resources to operate reliably. While other parties may share this interest, goals regarding preferred resources may take priority over practical considerations, and economic self-interest may shade recommendations that run contrary to the CAISO's proposals. The Commission should resolve any doubt about which direction to take in favor of the need determination and procurement path recommended by the CAISO.

Notably, SCE has endorsed CAISO's analysis as the basis for a need finding in the SCE service area. SCE's witness Carl Silsbee testified:

> The CAISO's opening testimony recommends that 2,370 MW of existing generation in the Western LA Basin area must remain in service or be replaced with similarly located new generation. CAISO also states that up to 3741 MW of new generation may be needed if new generation is not located near existing generation. This is based on an analysis of LCR needs in 2021. The CAISO also finds a need to retain or replace 430 MW of generation in the Big Creek/Ventura area. SCE has carefully reviewed the CAISO's LCR analysis. SCE also

4 Exhibit ISO-1 (Sparks Direct), p. 17, lines 10-14.

5 The CAISO determined that the retirement of OTC generation in the Pacific Gas and Electric Company service territory is not expected to create local capacity deficiencies. Exhibit ISO-1 (Sparks Direct), p. 3, lines 4-7. San Diego Gas & Electric Company has a separate application proceeding pending in which its needs for new local generation are being considered (A.11-05-023).

conducted discovery to understand the assumptions and methodologies underlying CAISO's findings. **Overall, SCE is satisfied with the CAISO's analysis as the basis for a need finding**.[6]

Based on the deference owed to the CAISO as the expert on which resources are needed to maintain reliability, as well as SCE's concurrence with the CAISO's analysis, the Commission should find that 430 megawatts of new capacity are required in Big Creek/Ventura.

A. CAISO's LCR And Once-Through Cooling (OTC) Generation Studies

The Water Board's OTC Policy, adopted in 2010, states:

> During the development of this Policy, State Water Board staff has met regularly with representatives from the California Energy Commission (CEC), California Public Utilities Commission (CPUC), California Coastal Commission (CCC), California State Lands Commission (SLC), California Air Resources Board (ARB), and California Independent System Operator (CAISO) **to develop realistic implementation plans and schedules** for this Policy that will not cause disruption in the State's electrical power supply.[7]

The Commission should rely on the OTC study to authorize procurement to meet LCR needs. The CAISO's OTC study is the result of years of analysis that commenced long before adoption of the OTC Policy. It is the culmination of a long process that considered input from the Commission and other agencies with regulatory oversight affecting the electricity system.

Additional studies recommended by some parties are not warranted and would only delay procurement. As discussed in more detail below, any delay in procurement jeopardizes the State's ability to meet the OTC compliance deadlines that the Commission helped establish. The Commission must not make the OTC Policy's compliance deadlines a burden on the State's electric grid, or conversely, force the Water Board to reconsider compliance deadlines, when the Commission collaborated with the Water Board to set those deadlines in the first place.

---

[6] Exhibit SCE-1 (Silsbee Direct), p. 3, line 19 – p. 4, line 2 (footnotes omitted; emphasis added).

[7] Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, Section 1.H., California State Water Resources Control Board, adopted May 4, 2010 (emphasis added).

B. Consideration Of Preferred Resources, Including Uncommitted Energy Efficiency, Demand Response, Combined Heat and Power, and Distributed Generation, In Determining Future LCR Needs

The record shows that the CAISO properly considered preferred resources in determining future LCR needs. Testimony supports the CAISO's determination of how to factor in preferred resources.[8] The CAISO's recommendations for local capacity requirements satisfy applicable policy objectives and the Commission should adopt them.

C. Appropriate Assumptions Concerning Retirement of OTC Generation

As noted above, both the CAISO and the Commission collaborated with the Water Board to establish realistic schedules to allow compliance with the OTC Policy without jeopardizing grid reliability. Absent concrete evidence to the contrary, the Commission should assume OTC generation retires consistent with the deadlines for compliance in the OTC Policy. This assumption is a necessary first step for ensuring that IOUs may procure the necessary replacement capacity in the local areas where the OTC facilities are located.

For the GenOn plants in Big Creek/Ventura – the Mandalay Generating Station and the Ormond Beach Generating Station – GenOn originally submitted an implementation plan to the Water Board seeking permission to pursue Track 2 compliance.[9] However, Track 2 compliance requires time-consuming data gathering and, even assuming collection of the requisite data,

---

8 Exhibit ISO-1 (Sparks Direct), p. 15, lines 20-30; Exhibit ISO-6 (Millar Reply), p. 11, line 4 – p. 16, line 24; Exhibit ISO-3 (Sparks Supplemental adopted by Millar), p. 4, lines 15-19; (The ISO shares the CEC's concerns about uncommitted energy savings from uncommitted resources. To the extent such uncommitted resources ultimately develop, they can be helpful in reducing overall net-demand, but the ISO does not believe it is prudent to rely on uncommitted resources for assessing future local system needs and ensuring the reliability of the bulk power system."); Reporter's Transcript ("RT"), Vol. 3, August 9, 2012 (Millar-CAISO), p. 350, lines 5-27 (demand response), p. 393, line 2 – p. 395, line 19 (uncommitted energy efficiency), p. 404, lines 17-25 (energy storage), p. 405, lines 7-20 (distributed generation).

9 Exhibit GenOn-1 (Beatty Direct), p. 4, lines 7-8.

presents uncertainty as to ultimate feasibility.[10] To eliminate that uncertainty, GenOn now intends to pursue a retire and replace approach to compliance with the OTC Policy and will update its implementation plan to reflect this change.[11] Based on this evidence, the Commission should assume for planning purposes that the OTC units at the Mandalay Generating Station and Ormond Beach Generating Station will not operate after 2020.

D. Transmission And Other Means Of Mitigation

Some parties have suggested that the Commission should delay procurement and take additional time to study possible transmission alternatives that might reduce the need for new generation, particularly in Big Creek/Ventura.[12] Yet, the CAISO has been analyzing the possible alternatives for years now and has presented its recommendation that 430 megawatts of new capacity are needed in Big Creek/Ventura. In fact, the CAISO's transmission witness, Mr. Sparks, considered and rejected a transmission alternative before making his recommendation for 430 megawatts of new capacity in Big Creek/Ventura.[13]

The CAISO has thoroughly considered transmission upgrades as an alternative to retaining local generation. The CAISO conducts a comprehensive analysis of the grid, including the local areas, each year in the transmission planning process.[14] The CAISO and the IOUs are continuously assessing opportunities to enhance the transmission grid and regularly incorporate feasible upgrades in the ordinary course of the annual transmission planning process.[15] Over the last 14 years the CAISO has worked with SCE to identify transmission upgrades that would

---

10 Exhibit GenOn-1 (Beatty Direct), p. 5, lines 5-10.

11 Exhibit GenOn-1 (Beatty Direct), Exhibit 1 (attached to testimony).

12 Exhibit Calpine-2 (Calvert Reply), p. 2, lines 9-11.

13 Exhibit ISO-1 (Sparks Direct), p. 14, lines 12-14; RT, Vol. 2, August 8, 2012 (Sparks for CAISO), p. 183, lines 19-25 ("we did identify a transmission alternative where we would install a shunt capacitor reactive support, which could reduce that. But given the amount of reactive support that was necessary and the potential cost, we -- we did not recommend that at this point in time.").

14 Exhibit ISO-3 (Sparks Reply), p. 4, lines 28-29.

15 RT, Vol. 4, August 10, 2012 (Cushnie for SCE), p. 751, lines 5-10.

reduce the need for local generation capacity, and numerous transmission upgrades have been added to the system "for the sole purpose of minimizing reliance on local generation capacity for local reliability."[16] As Mr. Sparks testified, "additional studies would not produce any significant changes in the need for local generation capacity."[17] For these reasons, the Commission should not delay the start of procurement in Track 1 to conduct further study of transmission solutions.

Transmission alone is not a desirable substitute for local generation, and eliminating LCR needs through added transmission should not be the objective of this planning process. Just one earthquake that disables a critical substation is enough to take down the grid and leave a sub-area dark, as occurred in Big Creek/Ventura during the Northridge earthquake.[18] The LCR needs identified in the CAISO's studies result from contingencies "occurring on the grid and the need for operators to have resources that can move very quickly with a full range of flexibility to alleviate that contingency."[19] Local generation offers more flexibility and effectiveness than transmission solutions alone.[20]

Furthermore, as the Commission is well aware, transmission takes a long time to build and presents siting, permitting and feasibility challenges of its own. Calpine's reply witness, Mr. Calvert, purported to show that transmission projects could be built as alternatives to retaining local generation in Big Creek/Ventura, and offered three options as "illustrative" examples of such projects. Mr. Calvert characterized his analysis as "preliminary,"[21] and readily admitted that he conducted very little (and maybe no) analysis of the feasibility of his purported

---

16 Exhibit ISO-3 (Sparks Reply), p. 5, lines 2-7.

17 Exhibit ISO-3 (Sparks Reply), p. 5, lines 12-13.

18 RT, Vol. 5, August 13, 2012 (Cabbell for SCE), p. 811, line 17 – p. 812, line 11.

19 RT, Vol. 4, August 10, 2012 (Cushnie for SCE), p. 663, lines 7-13.

20 Exhibit ISO-23 (Sparks Sur-Rebuttal), p. 4, lines 10-14; RT, Vol. 2, August 8, 2012 (Sparks for CAISO), p. 184, lines 22-26, and p. 185, lines 7-22; RT, Vol. 3, August 9, 2012 (Millar for CAISO), p. 363, line 19 – p. 364, line 2 (describing capacitor banks and reactors as "blunt instruments" that provide "no variability from zero to full." "They are either in or out of service.").

21 Exhibit Calpine-2 (Calvert Reply), p. 1, lines 16-18.

transmission alternatives.[22] Preliminary analyses and illustrative examples of transmission projects should not drive Commission decisions, particularly on issues as important as local reliability.

Calpine's purported examples of transmission projects are not feasible or desirable solutions for addressing local reliability needs, and they do not support a delay in procuring local generation. SCE's witness Cabbell, a transmission expert, exposed several weaknesses in the Calpine alternatives. Ms. Cabbell confirmed that SCE specifically modified the transmission system in Big Creek/Ventura after the Northridge earthquake to avoid the precise outcome proposed by Mr. Calvert as his Option 1 alternative.[23] Mr. Calvert's Option 1 proposal to loop an existing transmission line into the Pardee substation ignores the fact that SCE deliberately "de-looped" that line after the earthquake.[24] Mr. Calvert's Option 1 thus would undo a solution that SCE put in place to preserve local reliability and betrays a lack of familiarity with the local transmission system. Ms. Cabbell confirmed that she would have concerns about looping the line back into the Pardee substation.[25]

Ms. Cabbell also confirmed that SCE does not deploy series capacitors in its 230 kV system, showing that Mr. Calvert's Option 2 alternative (which would add series capacitors to two 230 kV lines) would introduce equipment not currently used on the SCE 230 kV system.[26] Ms. Cabbell also confirmed that the installation of series capacitors can cause problems with subsynchronous resonance[27] that could be damaging to nearby generating equipment. Mr.

---

22 RT, Vol. 8, August 16, 2012 (Calvert for Calpine), p. 1311, lines 20-22 ("I should point out that this is not a definitive analysis. It is not a comprehensive analysis."), and p. 1314, line 27 – p. 1315, line 6 ("The feasibility of the alternatives is really more in Southern Cal Edison and California ISO's wheelhouse, not mine.").

23 RT, Vol. 5, August 13, 2012 (Cabbell for SCE), p. 811, line 17 – p. 812, line 11.

24 RT, Vol. 5, August 13, 2012 (Cabbell for SCE), p. 812, lines 3-11.

25 RT, Vol. 5, August 13, 2012 (Cabbell for SCE), p. 812, lines 12-14.

26 RT, Vol. 5, August 13, 2012 (Cabbell for SCE), p. 809, lines 20-27.

27 RT, Vol. 5, August 13, 2012 (Cabbell for SCE), p. 809, line 28 – page 810, line 9.

Calvert's recommended Option 2 transmission alternative thus could make it more difficult to operate or replace local generation in the Moorpark subarea.

Mr. Calvert's Option 3 suggestion, which would install a fourth transmission line in the same corridor occupied by three existing lines, is also flawed. When asked whether a fourth line would protect local reliability if there were a fire in the transmission corridor where all four lines are located, Mr. Calvert replied that his contingency simulation was not designed to consider this type of "real world event."[28] Mr. Calvert also apparently misunderstood the scope of the CAISO's OTC study analysis, at one point alleging that the CAISO did not consider Category D contingencies,[29] when in fact the CAISO did look at Category D contingencies when analyzing the Moorpark sub-area in Big Creek/Ventura.[30]

Mr. Calvert's analysis apparently did not consider whether his alternatives would actually be effective in meeting local reliability needs. Mr. Calvert considered whether an alternative made his model work successfully without local generation, but he confirmed that he was not concerned with whether it would provide a local reliability solution for a "real world event." Any transmission upgrades should be feasible and desirable in the real world, not just because they make someone's power flow model work without local generation in the theoretical world.

CAISO sur-reply testimony also undermines Calpine's testimony. As Mr. Sparks states, "Mr. Calvert's options are not compelling enough to put the procurement process in the Moorpark area on hold."[31]

Designing and implementing transmission upgrades, even assuming they are feasible, would take a long time. And if they are built they will still likely not eliminate all need for local

---

[28] RT, Vol. 8, August 16, 2012 (Calvert for Calpine), p. 1329, lines 1-3.

[29] RT, Vol. 8, August 16, 2012 (Calvert for Calpine), p. 1329, line 26 – p. 1330, line 3 ("Q: I guess the question I am asking, that wasn't something you analyzed in your analysis; is that correct? A: No. That's beyond the scope – that's a Category D outage. You don't study those.").

[30] Exhibit ISO-3 (Sparks Reply), p. 7, line 4 – p. 8, line 12; *see also* Exhibit TURN-1 (Woodruff Direct), p. 12, lines 5-11.

[31] Exhibit ISO-23 (Sparks Sur-Rebuttal), p. 6, lines 3-4.

capacity in Big Creek/Ventura. Further study of transmission alternatives would only delay the start of procurement to meet local reliability needs. To allow for timely compliance with the OTC Policy and ensure adequate resources in Big Creek/Ventura, the Commission should reject self-serving offers of further delay to consider largely unfounded transmission alternatives. The Commission should direct SCE to procure the 430 MW of replacement capacity advocated by the CAISO to maintain local reliability in Big Creek/Ventura.

III.

DETERMINATION OF LCR NEED SPECIFIC TO LA BASIN AND BIG CREEK/VENTURA AREA

A. LA Basin

SCE accurately identifies numerous challenges to building new plants in the LA Basin and wisely recommends starting procurement now.[32] These timing considerations apply equally to Big Creek/Ventura and support immediate start of procurement there as well.[33]

B. Big Creek/Ventura Area

The Commission should authorize procurement in Big Creek/Ventura consistent with the CAISO's recommendation. The CAISO determined that 430 megawatts of OTC replacement capacity are necessary to "ensure that the overall changes to the operation of the Moorpark area and the southern California transmission system are moderated, and unforeseen consequences in the form of adverse impacts on the transmission system operation are minimized."[34] Based on the CAISO's testimony, the Commission should mandate procurement of 430 megawatts to maintain local reliability in Big Creek/Ventura.

---

32 Exhibit SCE-1 (Silsbee, Minick), p. 12, line 20 – p. 15, line 6.

33 Exhibit GenOn-2 (Beatty Reply), p. 8, lines 2-7 and p. 5, line 4 – p. 6, line 8.

34 Exhibit ISO-23 (Sparks Sur-Rebuttal), p. 4, lines 10-14.

As discussed above, the Commission should not delay procurement to conduct further studies. The CAISO studies transmission alternatives every year.[35] Calpine's three "illustrative" transmission alternatives in Big Creek/Ventura are not viable and do not support a delay in procurement, as discussed in detail in Section II.D above. The CAISO and the Commission have been collaborating with the Water Board for several years to identify a schedule for OTC Policy compliance. The time for studies has passed. The time is now to commence procurement to comply with the OTC Policy while preserving reliability in Big Creek/Ventura.

IV.

PROCUREMENT OF LCR RESOURCES AND INCORPORATION OF THE PREFERRED LOADING ORDER IN LCR PROCUREMENT

A. Incorporation Of The Preferred Loading Order In LCR Procurement

CAISO witness Mr. Millar explained the criteria that should determine whether a resource can fill local capacity deficiencies. Mr. Millar explained that resources must be "substitutable for conventional (thermal) generation and must be location specific," and "should be able to respond to dispatch instructions and should have sufficient durability to remain in service over the needed period of operation."[36] To successfully bid into the procurement process, Mr. Millar testified that resources must be capable of reacting in the time frames necessary to address transmission system issues.[37] The Commission's preferred loading order dictates that resources meeting these criteria should be selected according to their rank in the loading order.

---

[35] Exhibit ISO-3 (Sparks Reply), p. 4, lines 28-29.

[36] Exhibit ISO-6 (Millar Reply), p. 17, lines 25 – 29.

[37] Exhibit ISO-6 (Millar Reply), p. 17, line 29 – p. 18, line 3 ("Relying on resources without these characteristics to meet local needs under stressed system conditions will leave operators with few options to meet reliability standards.").

B. Other Commission Policies and Consideration Affecting LCR Procurement

The primary factor that should drive the Commission's decision in Track 1 is the very reason for Track 1's existence: the OTC Policy. In particular, the Commission should resist the suggestion that the Water Board's OTC Policy deadlines are flexible. The Water Board gave the Commission over ten years to ensure that OTC facilities could comply with the OTC Policy, in most cases through retirement. The Commission should not now undermine the very deadlines it helped establish by delaying replacement of impacted OTC facilities.

C. If A Need Is Determined, How The Commission Should Direct LCR Need To Be Met

The Commission should establish at least two principles in setting procurement authorization. First, the Commission should set a minimum amount that the IOU is directed to procure. Second, the Commission should give the IOU flexibility in the manner of procurement.

SCE has asked for extreme flexibility to procure new generation, to the point that SCE could elect not to procure anything at all. SCE's proposal would allow SCE to decline to procure any new capacity, even if the Commission finds a need for it.[38] SCE's proposal begs the question why the Commission should create a record and make a need determination if the utility can later decide not to act on the Commission's determination. SCE's proposal also exposes that there are only indirect consequences to the utility if it procures inadequate generation; the Commission will undoubtedly be held responsible for any under-procurement and loss of grid reliability by utilities under its jurisdiction. Accordingly, if the Commission determines that there is a need for new generation, the Commission's decision should not only authorize the utility to procure, it should also mandate that the utility procure the minimum amount needed.[39]

---

[38] RT, Vol. 4, August 10, 2012 (Cushnie for SCE), p. 717, line 24 – p. 718, line 7.

[39] Exhibit TURN-1 (Woodruff Direct), p. 22, lines 11-28 ("The Commission should adopt one or more of the following policies to help Edison manage the procurement of any needed local capacity. . . . Providing minimum and maximum procurement targets (a) to ensure some truly needed minimum amount is procured . . ..").

This is consistent with the nature of the CAISO's recommendation, which identifies the **minimum** amount of capacity needed to maintain local reliability.[40]

SCE also requests the option to rely on either a competitive solicitation process through a request for offers ("RFO") or to engage in bilateral negotiations to procure new generation.[41] Recognizing the unique circumstances presented by procuring generation to satisfy specific local reliability requirements, GenOn concurs that SCE should be given the option to procure new generation through RFOs or bilateral negotiations. Under either scenario, a contract would be heavily vetted through the Commission's procurement review process and ultimately be put before the Commission for approval through an application process.[42]

D. Appropriate Method(s) of Procurement

GenOn's preferred method of procurement is through the use of competitive solicitations. However, GenOn is sensitive to the concerns regarding perceived market power expressed by both SCE and TURN.[43] On that basis, GenOn also supports the use of cost-based, bilaterally negotiated contracts authorized under California Assembly Bill 1576 as a vehicle for procuring new generation.[44]

E. Timing Of Procurement

Timing of procurement is the most critical issue in Track 1. GenOn can and has provided compelling evidence on this point. GenOn and other independent power producer competitors are not well situated to tell the Commission how many megawatts are needed to protect local reliability. Such opinions by any wholesale power provider, whether recommending capacity

---

40 Exhibit ISO-6 (Millar Reply), p. 3, lines 3-6.

41 Exhibit SCE-1 (Cushnie Direct), p. 21, line 18 – p. 22, line 8.

42 RT, Vol. 4, August 10, 2012 (Cushnie for SCE), p. 718, line 21 – p. 720, line 7.

43 Exhibit SCE-1 (Cushnie Direct), p. 23, line 4 – p. 24, line 22; Exhibit TURN-1 (Woodruff Direct), p. 20, line 19 – p. 23, line 2.

44 Exhibit GenOn-2 (Beatty Reply), p. 12, line 1 – p. 13, line 3.

additions or recommending transmission alternatives to benefit their existing assets by eliminating competing local power projects, are undoubtedly biased by self-interest. For that reason, GenOn has not provided evidence suggesting how much new capacity, if any, is required to replace OTC facilities. The CAISO is the appropriate party to sponsor that evidence and make those recommendations.

GenOn is, however, an expert on how long it takes to develop new electric generation projects in California. Based on its experience and expertise, GenOn has demonstrated that the Commission must authorize procurement by early 2013 if it is going to rely on replacement generation to meet the 2020 deadline for the Big Creek/Ventura OTC facilities.

GenOn's testimony shows that, in the current regulatory environment, the Commission should expect a project development timeline of seven years, broken down as follows:

- 18 months from the time a utility issues its RFO to finalize and execute the power purchase agreement ("PPA");
- 24 months to secure CEC approval and required air permits including federal Prevention of Significant Deterioration ("PSD") permit (this assumes filings are made when the PPA is executed; Commission approval of the PPA is subsumed within this time frame);
- 12 months for the PSD appeal process to be completed after permits are issued; and
- 27 months for construction.
- TOTAL ELAPSED TIME: 81 months, or approximately seven years.[45]

Other testimony supports this seven year timeline. Independent Energy Producers Association witness, William Monsen, testified that "it is not unusual for new conventional resources to require 6-8 years or more to move from a planned project, through the RFO selection process, then through the construction phase, to achieve a commercial online date

[45] Exhibit GenOn-2 (Beatty Reply), p. 6, lines 9-19.

(COD)."[46] Testimony by the CAISO's witnesses also confirms that seven years is the realistic time frame for building a new conventional resource.[47] And SCE's witness, Mr. Minick acknowledged during cross-examination that "it seems to be taking longer now than it's ever taken in the past to go through all these hurdles on getting something built."[48] Mr. Minick also testified that "it is not unreasonable to assume seven to nine years" to build a new power plant.[49]

Indeed, one need look no further than the winning projects from past RFOs to confirm that seven years is the expected timeline for project development and construction.[50] The seven year timeline is not likely to be accelerated for simple cycle (as opposed to combined cycle) technology. Any utility scale project, whether configured as combined cycle or simple cycle, will require the same amount of time to obtain and negotiate a PPA, obtain permits (including PSD review, which is likely to be triggered even for relatively small gas-fired projects under the new tailoring rule requirements),[51] and close financing. While some witnesses suggested that construction could occur more quickly for a simple cycle project, GenOn's testimony shows that the construction period for simple cycle projects is still lengthy. The GenOn Marsh Landing Generating Station, currently under construction and described in GenOn's testimony, is a simple cycle plant. Construction of that facility is expected to take a total of 27 months, consistent with the timeline shown above.

SCE nonetheless advocates postponing a need determination in Big Creek/Ventura until the next LTPP cycle.[52] Punting a decision on Big Creek/Ventura means there will not be a need

---

46 Exhibit IEP-1 (Monsen Reply), p. 13, lines 12-15.

47 RT. Vol. 2, August 8, 2012 (Rothleder for CAISO), p. 313, lines 10-14; RT, Vol. 3, August 9, 2012 (Millar for CAISO), p. 371, line 18 – p. 372, line 6.

48 RT, Vol. 6, August 14, 2012 (Minick for SCE), p. 1002, lines 10-13.

49 RT, Vol. 6, August 14, 2012 (Minick for SCE), p. 1002, lines 2-3.

50 Exhibit GenOn-2 (Beatty Reply), Exhibit 1 titled "Development Cycle Timeline for Recent Long-Term RFO Winning Projects" (lists three winning projects from SCE's 2006 RFO, all with a projected timeline of seven years from RFO issuance to expected COD, assuming COD occurs on schedule).

51 Exhibit GenOn-2 (Beatty Reply), p. 4, line 19 – p. 5, line 3.

52 Exhibit SCE-1 (Minick Direct), p. 10, lines 12-13.

determination until 2015 at the earliest. Even that may not be realistic given that completion of this LTPP cycle will take at least another year, and it is not clear whether the next LTPP cycle could be conducted on a schedule that allows a decision by the end of 2015. The time required for SCE to make its procurement selections and prepare and submit an application for approval (estimated to take up to two years after the Commission adopts a need determination),[53] and then to complete the application process, further demonstrates that the Commission should require SCE to start its procurement process for Big Creek/Ventura as soon as possible.

Given the time it takes to build new resources, the Commission simply cannot wait until 2015 or later and expect to meet the deadlines in the OTC Policy. As explained several times during the hearings, deferral will foreclose the option to use conventional thermal generating technology – currently the only technology known to be capable of providing the characteristics the CAISO requires to meet local reliability needs.[54] To preserve the option to utilize this proven technology, the Commission should reject SCE's recommendation to delay a need determination for Big Creek/Ventura until the next LTPP cycle.

V.

INCORPORATION OF FLEXIBLE CAPACITY ATTRIBUTES IN LCR PROCUREMENT

A. If A Need Is Determined, Should Flexible Capacity Attributes Be Incorporated Into Procurement

B. Additional Rules, Not Already Covered By Resource Adequacy (RA) Rules, To Govern LCR Procurement

---

53 RT, Vol. 4, August 10, 2012 (Cushnie for SCE), p. 718, line 21 – p. 720, line 7, and p. 734, line 14 – p. 735, line 5.

54 RT, Vol. 2, August 8, 2012 (Sparks for CAISO), p. 196, line 22 – p. 197, line 4, and p. 203, lines 3-7; RT, Vol. 3, August 9, 2012 (Millar for CAISO), p. 371, line 22 – p. 372, line 17, and p. 400, lines 22-28, and p. 460, lines 12-19 ("But what we do know is that if we don't move on a timely basis and start this process, at this point one of the few options that we see that provides thosecharacteristics would run out of lead time."), and p. 466, lines 12-24.

VI.

COST ALLOCATION MECHANISM (CAM)

A. Proposed Allocation Of Costs Of Needed LCR Resources

B. Should CAM Be Modified At This Time?

C. Should Load Serving Entities (LSEs) Be Able To Opt Out Of CAM?

VII.

OTHER ISSUES

A. SCE Capital Structure Proposal

B. Coordination of Overlapping Issues Between R.12-03-014 (LTPP), R.11-10-023 (RA), And A.11-05-023

C. SCE Statewide Cost Allocation Proposal

D. CAISO Backstop Procurement Authority To Avoid Violating Federal Reliability Requirements

E. Energy Storage

VIII.

CONCLUSION

Based on the foregoing, the Commission should adopt the CAISO's recommendation and mandate that SCE procure a minimum of 430 megawatts of new capacity to address the deficiency in Big Creek/Ventura. Given that the timeline to construct new electric generation facilities is at least seven years, the Commission cannot wait until the next LTPP cycle. The Commission must act now to meet the deadlines established in the OTC Policy, a policy the Commission helped create.

September 24, 2012

Respectfully submitted,

/s/ Lisa A. Cottle

Lisa A. Cottle
Winston & Strawn, LLP
101 California Street, Suite 3900
San Francisco, California 94111
Telephone: 415-591-1579
Facsimile: 415-591-1400
lcottle@winston.com

Attorneys for GenOn Energy, Inc.