Docket No.: R.12-03-014

Exhibit No.:

Witness: Sean Beatty

Date: July 23, 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)

LOCAL RELIABILITY TRACK I REPLY TESTIMONY OF SEAN BEATTY ON BEHALF OF GENON ENERGY, INC.

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.

July 23, 2012

I. INTRODUCTION.

Q. What is your name, employer and title?

A. My name is Sean Beatty, and I am Director, West Regulatory Affairs and Associate General Counsel of GenOn Energy, Inc. (GenOn).

Q. Have you previously sponsored testimony in this proceeding?

A. Yes. I sponsored direct testimony in this proceeding which was served on June 25, 2012.

Q. Please summarize the topics you will address in your reply testimony.

A. In testimony served on June 25, 2012, Southern California Edison Company (SCE) recommended that the Commission defer authorizing procurement of new generation in the Big Creek/Ventura local capacity area until the 2014 long-term procurement plan (LTPP) cycle. SCE based this recommendation on several contentions, namely the contention that developing a project in Big Creek/Ventura is less challenging than in the L.A. Basin, and the contention that GenOn's implementation plans with respect to the State Water Resource Control Board's (SWRCB's) Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Policy) are undergoing amendment. SCE testified that the Commission should wait until such amendments are complete before issuing a procurement decision. In response, this reply testimony addresses project development timelines in California and provides further details regarding GenOn's implementation plans in connection with the OTC Policy.

Q. Does GenOn agree with SCE's recommendation to delay a procurement decision for the Big Creek/Ventura local capacity area?

A. No. Based on the SWRCB's 2020 OTC Policy compliance deadline and the time it takes to develop new projects in California, it is imperative that the Commission adopt a procurement decision for Big Creek/Ventura in Track 1 of this proceeding. Based on publicly available data on the California Energy Commission's (CEC's) website, it is reasonable to expect future development of new natural gas-fired generation in California to require at least seven years, and potentially longer, from the time that development begins to the commencement of commercial operation. As explained below, this seven year plus time frame is supported by review of a recent project that is under construction, and the regulatory framework that now applies to new natural gas-fired projects. To meet the CAISO's projected need for new generating capacity in the Big Creek/Ventura local reliability area in 2020, it is necessary to adopt a need determination by the end of 2012, and to require the utility to commence competitive solicitations for such capacity in 2013 to support project development.

Q. Does your reply testimony address any other topics?

A. Yes. The Assigned Commissioner's Ruling issued on July 13, 2012 (ACR) asked parties to augment the record on three topics: (1) how the Commission should direct SCE and/or other load serving entities (LSEs) in the Big Creek/Ventura local area to procure capacity to meet identified long-term local capacity needs on behalf of the system; (2) how the Commission should allow SCE to meet some or all of the identified need through "cost plus" contracts outside of a competitive solicitation and whether Assembly Bill 1576

(AB 1576) (Cal. Public Util. Code § 454.6) provides clear guidance on the options available to SCE or whether there is a need to interpret the statute's meaning in that context; and (3) what barriers exist to ensuring an effective all source request for offers (RFO) process, and what specific performance characteristics should be accounted for in an RFO to effectively enable the participation of non-traditional resources like energy storage, demand response and distributed generation. I address these topics in my reply testimony.

II. PROJECT DEVELOPMENT TIMELINE IN CALIFORNIA.

Q. What is GenOn's experience with project development in California?

A. An affiliate of GenOn developed and is currently constructing the Marsh Landing Generating Station (Marsh Landing), a 760 megawatt natural gas-fired peaking facility located near Antioch, California. Marsh Landing was one of the winning projects selected in the Pacific Gas and Electric Company (PG&E) 2008 long-term all source request for offers (LTRFO) process. Marsh Landing is on track to commence commercial operation in or around May 2013.

Q. Please describe the timeline for the Marsh Landing project.

A. PG&E conducted its 2008 LTRFO pursuant to the Commission's December 2007 decision (D.07-12-052) in a prior LTPP cycle, in which the Commission authorized PG&E to procure up to 1200 megawatts of new generating capacity. PG&E issued its LTRFO on April 1, 2008, and proposals were due at the end of July 2008. The GenOn affiliate submitted the Marsh Landing proposal at that time and commenced the CEC certification process in late May 2008. The issuance of PG&E's LTRFO in April 2008 effectively marked the beginning of development for the Marsh Landing project. The GenOn affiliate and PG&E entered into a long-term power purchase agreement (PPA) for the Marsh Landing project in September 2009, and several weeks later the GenOn affiliate submitted an amendment to its application for certification at the CEC to conform the project design with that reflected in the executed PPA. The Commission approved the PPA in July 2010. The CEC authorized construction of Marsh Landing in late August 2010. As noted above, construction is now underway and the Marsh Landing project is expected to be operating in the summer of 2013.

Q. Did Marsh Landing face any permitting obstacles?

A. By all accounts, Marsh Landing was a relatively non-controversial project that received its approvals without substantial active opposition.

Q. How long will it have taken to achieve commercial operation for Marsh Landing?

A. It will have taken more than five years from the issuance of PG&E's LTRFO (April 2008) to achieve commercial operation (Summer 2013).

Q. **Was it necessary to obtain a federal Prevention of Significant Deterioration (PSD) permit for Marsh Landing?**

A. No. As a peaking facility with relatively low total annual emissions, Marsh Landing did not require a federal PSD permit. Under new regulations in effect today, however, the Commission should expect all new natural gas-fired generating facilities to require a PSD permit. The U.S. Environmental Protection Agency (U.S. EPA) recently added carbon dioxide (CO_2) emissions and their equivalents to the PSD framework, which means that every new gas-fired generating project will be subject to PSD review for all emissions because of the relatively low threshold of CO_2 emissions required to trigger PSD review.

Q. What is the significance of the PSD permit process for development of new projects?

A. Determining best available control technology (BACT) for CO_2 emissions promises to be a contentious undertaking that has the potential to delay the permit process. In addition, where delegation to a local air district has not occurred, the appellate process embodied in the PSD framework allows parties who oppose a project to seek appellate review by the Environmental Appeals Board of the U.S. EPA (EAB) and the filing of such an appeal means that the project owner cannot commence construction until the appeal is resolved. Due to this appellate process, PSD review can be expected to add time, potentially as much as two years, to the permitting process for a new gas-fired power plant. Calpine's Russell City Energy Center project is an example of the delay that can result from a PSD appeal. Even if delegation of PSD responsibilities to a local air district has occurred, one can expect that it will take time for air districts to work their way through the process, particularly in the first few years after delegation occurs.

Q. Besides PSD permits and related appeals, are there other reasons to expect projects will take longer than historically experienced?

A. Yes. The limited availability of emission reduction credits, not just in the South Coast Air Quality Management District (SCAQMD), but in other air districts as well, complicates and has the potential to delay development of a new power plant. For example, the Ventura County Air Pollution Control District (VCAPCD), which is the agency responsible for air permitting in the Big Creek/Ventura local reliability area, does not have a liquid market for particulate matter emission reduction credits, nor does it have a program similar to that in the SCAQMD which allocates emission reduction credits on a megawatt for megawatt basis to new power plants that replace older power plants. New projects located in the VCAPCD will have to iron out these issues before any construction can begin. Also, recent CEC permitting cases have been taking two years or longer for gas-fired power plants, even though statutory requirements suggest the CEC is required to process such cases within one year.

Q. In the new permitting environment, how will the project development timeline play out for future projects?

A. Based roughly on the Marsh Landing example, with time added for resolution of a PSD appeal, a seven year development process would break down as follows:

- 18 months from the time a utility issues its LTRFO to finalize and execute the PPA;
- 24 months to secure CEC approval and required air permits including PSD permit (assumes filings are made when the PPA is executed);
- 12 months for the PSD appeal process to be completed after permits are issued;
- 27 months for construction.
- TOTAL ELAPSED TIME: 81 months, or approximately seven years

If the PSD appeal process takes longer than 12 months, as occurred with the Calpine Russell City project, or there is active opposition to a project at the CEC, then the seven year process could be extended.

Q. In light of these project development timelines, what must happen to bring new generation into operation in 2020?

A. Developers would need to receive the signal of an RFO during 2013 to commence the development process. Assuming that a new project can be completed in seven years (which may be optimistic), a procurement decision issued by the end of 2012, with a LTRFO to be issued in early 2013, should provide adequate time to conduct a competitive process and allow project developers to offer projects that could be operational in 2020.

Q. Do you have other information regarding the length of time it will have taken to construct some recent power plants?

A. Yes. Attached as Exhibit 1 to this reply testimony is a summary of power plants that received PPAs from recent LTRFOs issued by SCE and PG&E. The summary shows the date the LTRFO was issued and the estimated commercial operation dates for the projects that were selected. None of these projects were required to obtain PSD permits. This information was obtained from CPUC and CEC web sites.

Q. Do you agree with SCE's assertion in its opening testimony (page 10) that it is not as challenging to develop new local capacity requirements (LCR) generation in Big Creek/Ventura as in the LA Basin?

A. I am not aware of an objective measure to evaluate the relative difficulties of developing new generation in different geographic areas of California. Regardless of whether one geographic area is less “challenging” than another, GenOn’s experience is that it will take seven to nine years to develop new generation in California. In terms of timing of procurement, the Commission’s determination should not be based on whether one geographic area is more challenging than another, but instead on how long it will take to develop the megawatts needed in the local capacity area at issue.

Q. Has SCE provided any further details regarding its position that the Commission should defer authorizing procurement of new local capacity in the Big Creek/Ventura local reliability area “until the 2014 LTPP Cycle”?

A. Yes. In response to a data request from GenOn, SCE explained that it is recommending that procurement authorization be deferred until the LTPP regulatory proceeding cycle that is anticipated to begin in 2014 and cover the 10 year planning period from 2015 to 2024. SCE believes that a decision could be made by the Commission “by approximately the end of 2014.” *See* SCE’s Response to GenOn Data Request Set 1, Question 3, attached as Exhibit 2.

Q. Did SCE offer a view as to whether this would allow sufficient time to construct new generation to meet identified local capacity needs in 2020?

A. In response to another GenOn data request, SCE has stated that “in order to be available by the end of 2020, SCE anticipates a solicitation for new LCR generation would need to take place by approximately 2015.” *See* SCE’s Response to GenOn Data Request Set 1, Question 4(b), attached as Exhibit 3. SCE also responded that five to seven years is needed from the time of a solicitation for new capacity until the construction completion of new LCR generation, noting that the length of time required is dependent on many factors including the type of technology to be constructed. *See* SCE's Response to GenOn Data Request Set 1, Question 4(a), attached as Exhibit 4. SCE's schedule would work only if new LCR generation can be developed and built according to the minimum five year timeline cited in SCE's data response. As explained above, based on GenOn's experience and the current regulatory environment in California, it is unrealistic to expect that new generation can be built in only five years. A more realistic timeframe would allow for a minimum of seven years. SCE's proposal would not allow sufficient time for construction of LCR generation that the CAISO has determined is needed in the Big Creek/Ventura local reliability area by 2020.

Q. Do you agree with SCE's recommendation that the Commission defer authorizing new LCR generation in the Big Creek/Ventura local reliability area until the next LTPP cycle?

A. No. The CAISO has determined that new local capacity is needed in 2020, the year when the requirements of the OTC Policy take full effect. Assuming the issuance of an RFO in mid-2013, there will be only seven and a half years remaining before that deadline. To have new LCR generation in place to meet the 2020 deadline and allow the retirement of the OTC units, it is critical for the Commission to issue a need determination this year, and to direct the utility to commence a competitive solicitation for new LCR generation in 2013. Based on GenOn's experience developing projects, it would not be realistic to wait until 2015 to signal the start of new development to meet the LCR need.

III. STATUS OF GENON'S OTC IMPLEMENTATION PLANS.

Q. In its opening testimony (page 11, lines 3-5), SCE suggests that it would be prudent to delay a procurement decision for Big Creek/Ventura until GenOn's OTC implementation plans for its Mandalay Generating Station (MGS) and Ormond Beach Generating Station (OBGS) are "fully clarified." Do you agree?

A. No. Based on the letter exchange with the SWRCB, copies of which were provided as Exhibit 1 to my opening testimony, it is not readily apparent that there is any ambiguity in connection with GenOn's implementation plans under the OTC Policy, and certainly no ambiguity that would impact the timing of a Commission decision regarding Big Creek/Ventura. As discussed in my opening testimony, GenOn recently informed the SWRCB of GenOn's intention to modify the implementation plans for MGS and OBGS. Instead of pursuing Track 2 compliance, GenOn will now pursue a retire and replace approach to compliance. Under this approach, the existing capacity at MGS and OBGS would cease to operate on or around the compliance deadline specified by the OTC Policy. For purposes of a procurement decision, that is all the Commission really needs to know about MGS and OBGS. That said, GenOn intends to submit amended implementation plans for MGS and OBGS to the SWRCB later this summer. Those implementation plans will provide a high-level detail of what new generation might look like at each of the MGS and OBGS sites. Of course, until the Commission issues a procurement decision and the utility contracts for any new projects, the details regarding possible new construction at the MGS and OBGS sites is unavoidably speculative. In fact, the best path toward clarification of the MGS and OBGS implementation plans is for the Commission to issue a procurement decision for Big Creek/Ventura by the end of 2012, instead of deferring a decision as recommended by SCE.

IV. TOPICS RAISED IN THE ACR.

Q. The ACR asks how the Commission should direct SCE and/or other LSEs in the Big Creek/Ventura local area to procure capacity to meet long-term local capacity needs on behalf of the system. What is your response?

A. GenOn expects that the Commission will authorize the utility in the local area where need is identified to conduct a competitive RFO process that will lead to a long-term contract. As a recent developer of a project, it is GenOn's experience that a long-term agreement with a credit-worthy entity is necessary to secure financing for a new generation project. Having the utility remain in this role for this round of procurement is important given the timing of the need for new local capacity resources. SCE appears to oppose taking on this role for procurement in the Big Creek/Ventura local reliability area, and its opening testimony asks the Commission to establish a proceeding in conjunction with the CAISO to develop a forward capacity procurement mechanism. GenOn is not opposed to this recommendation in concept, but there is simply not adequate time to implement it to meet the identified need for local capacity additions by 2020. Realistically the only way to meet the local reliability need identified in the CAISO's study by 2020 is for the Commission to direct the utility to procure new capacity resources. For the reasons explained above, this urgency applies to the Big Creek/Ventura local reliability area and not just to the L.A. Basin local reliability area as SCE suggests.

Q. The ACR also asks how the Commission should allow SCE to meet some or all of the identified need through "cost plus" contracts outside of a competitive solicitation and whether AB 1576 provides clear guidance on the options available to SCE or whether there is a need to interpret the statute's meaning in that context. What is your response?

A. GenOn generally agrees with SCE's recommendations in its opening testimony regarding how AB 1576 cost of service contracts can provide one mechanism for securing new generation needed to meet local reliability needs. A competitive solicitation should be the preferred mechanism for soliciting new resources that can meet the identified need. But if the solicitation is not successful or does not yield sufficiently robust results (if, for example, the solicitation yields only a single offer or only a small number of offers), then the utility should have the flexibility to enter into a contract consistent with the provisions set forth in AB 1576. AB 1576 does not require any additional clarification by the Commission. Instead, the utility should be permitted to negotiate a contract subject to the authority identified in AB 1576, and the resulting terms of any such negotiated agreement would be subject to a reasonableness review by an Independent Evaluator, the Procurement Review Group, and the Commission. In the case of an AB 1576 contract, GenOn would expect that the reasonableness of that contract would be evaluated, in part, based on the terms of other contracts entered into by utilities in California in recent years.

As a matter of efficiency to ensure that the development timeline can be accommodated, the Commission should allow the utility to engage in bilateral discussions for a cost-of-service contract at the same time it is conducting a competitive solicitation, or on a parallel path with the competitive solicitation. In other words, it should not be necessary to show that a competitive solicitation failed as a condition to start engaging in a bilateral negotiation. The two processes could proceed on parallel paths to ensure that new resources can be solicited and contracts signed expeditiously.

Q. The ACR asks, "In the past, the Commission has allowed all source Request for Offers (RFOs) for incremental resources in which any type of resource could compete to fill an identified need. What barriers may currently exist to ensuring effective all source RFOs? What specific performance characteristics should be accounted for in this RFO to effectively enable the participation of non-traditional resources like energy storage, demand response and distributed generation? Would the Commission need to be specific about the characteristics of the resources needed to meet the need (e.g., minimum hours of availability required to meet local reliability needs)? If so, what characteristics should the Commission require?" What is your response?

A. I will leave it to providers of non-traditional resources to identify any perceived barriers to market entry, other than the cost of their technologies. In addition, I am not an electrical engineer and cannot opine on the characteristics of resources the CAISO may require to ensure local reliability standards are met. That said, with one exception, the Commission need not modify the general directives issued to utilities in prior LTPP decisions (most recently D.07-12-052) to procure least cost, best fit resources. The exception to previous LTPP decisions is that the procurement authorizations in those decisions were not directed to specific local capacity areas. In this case, the authorization is specific to local capacity areas, and the Commission's decision should explicitly require that the procurement of new capacity occur in a way to satisfy the local capacity area need.

Q. Does this conclude your testimony?

A. Yes, it does.

R.12-03-014
Local Reliability Track 1 Reply Testimony of Sean Beatty on behalf of GenOn Energy, Inc.
July 23, 2012

Exhibit 1

Development Cycle Timeline for Recent Long-Term RFO Winning Projects

(see attached page)

Development Cycle Timeline for Recent Long-Term

RFO Winning Projects

Long-Term RFOs for PG&E and SCE					
Utility	RFO Date	Winning Project	MW	COD[1]	RFO to COD (approx. years)
	4/1/2008	Marsh Landing Generating Station	760	5/1/2013	5
	4/1/2008	Oakley Generating Station	614	6/1/2016	8
PG&E	4/1/2008	Mariposa Energy Project	196	7/1/2012	4
	8/14/2006	CPV Sentinel Units 1-8	850	8/1/2013	7
	8/14/2006	El Segundo Units 1 & 2	275	8/1/2013	7
SCE	8/14/2006	Walnut Creek	479	6/1/2013	7

[1] *Dates are based on the latest published CEC and CPUC data and are estimates. Actual CODs could be later.*

Exhibit 2

SCE's Response to GenOn Data Request Set 1, Question 3

(see attached page)

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

DATA REQUEST SET R.12-03-014 GenOn-SCE-001

To: GENON
Prepared by: Mohan Kondragunta
Title: Manager Project/Product
Dated: 07/03/2012

Question 03:

3. In the Testimony of Southern California Edison Company on Local Capacity Requirements that was served on June 25, 2012 ("SCE Testimony"), SCE witness Mark Minick testifies on page 10 at lines 12-13 that "The Commission Should Defer Authorizing LCR Generation in the Ventura/Big Creek Area Until the 2014 LTPP Cycle." Referring to that statement, please answer the following:

a. Please define "the 2014 LTPP Cycle" as used in the statement quoted above.

b. If the Commission defers authorizing procurement as recommended by SCE, by what date does SCE propose that the Commission authorize procurement of LCR generation in the Ventura/Big Creek Area?

c. If the Commission defers authorizing procurement as recommended by SCE, by what date does SCE propose that new LCR generation in the Ventura/Big Creek Area be solicited?

Response to Question 03:

a. The 2014 LTPP Cycle" is the next CPUC LTPP regulatory proceeding cycle. This LTPP cycle would be anticipated to begin in 2014 and cover the 10 year planning period from 2015-2024.

b. SCE would prefer the authorization of new LCR generation in the Ventura/Big Creek Area be based on the a Commission decision, possibly in the 2014 LTPP cycle, as that decision would incorporate updated assumptions and may include possibly updated CAISO transmission planning results. SCE believes these decisions could be made by the Commission by approximately the end of 2014.

c. As indicated in SCE's LCR testimony, SCE would like to have a multi-year forward procurement mechanism adopted. If such a mechanism is in place by the end of 2014, then the structure of this mechanism would presumably affect the timing of LSE procurement efforts. SCE does not currently have a recommendation for when new LCR generation solicitation would take place in the Ventura/Big Creek area.

Exhibit 3

SCE's Response to GenOn Data Request Set 1, Question 4(b)

(see attached page)

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

DATA REQUEST SET R.12-03-014 GenOn-SCE-001

To: GENON
Prepared by: Mohan Kondragunta
Title: Manager Projectr/Product
Dated: 07/03/2012

Question 04.b:

4. In the SCE Testimony, SCE witness Mark Minick testifies on page 10 at lines 20-22 that "Even if mitigation plans change, construction of new LCR generation can be completed more quickly and easily than in the LA Basin. Thus, SCE sees no immediate need to consider procurement of resources in the Big Creek/Ventura area." Referring to those statements, please answer the following:

b. If new LCR generation in the Big Creek/Ventura area is needed by 2020, by what date would SCE propose to commence a solicitation for new LCR generation?

Response to Question 04.b:

SCE has not proposed to commence a solicitation for new LCR generation in the Big Creek/Ventura area. In order to be available by the end of 2020, SCE anticipates a solicitation for new LCR generation would need to take place by approximately 2015.

Exhibit 4

SCE's Response to GenOn Data Request Set 1, Question 4(a)

(see attached page)

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

DATA REQUEST SET R.12-03-014 GenOn-SCE-001

To: GENON
Prepared by: Mohan Kondragunta
Title: Managaer Project/Product
Dated: 07/03/2012

Question 04.a:

4. In the SCE Testimony, SCE witness Mark Minick testifies on page 10 at lines 20-22 that "Even if mitigation plans change, construction of new LCR generation can be completed more quickly and easily than in the LA Basin. Thus, SCE sees no immediate need to consider procurement of resources in the Big Creek/Ventura area." Referring to those statements, please answer the following:

a. How much time is needed for construction of new LCR generation in the Big Creek/Ventura area?

Response to Question 04.a:

a. As a general rule, it is my professional estimation that 5 to 7 years is needed from the time of solicitation until the construction completion of new LCR generation. The length of time required is dependent on many factors including the type of technology to be constructed.