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)

COMMENTS OF ENERNOC, INC., ON ENERGY DIVISION'S LTPP STANDARD PLANNING ASSUMPTIONS STRAW PROPOSAL

May 31, 2012

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EnerNOC, Inc. (EnerNOC) respectfully submits these Comments on the Energy Division's Straw Proposal on Standard Planning Assumptions to be used in the Investor Owned Utilities (IOUs') Long Term Procurement Plans (LTPPs) ("Straw Proposal"). EnerNOC's Comments are focused primarily on the energy efficiency and demand response assumptions that are used to develop the demand and supply forecasts. These Comments are filed and served pursuant to the Commission's Rules of Practice and Procedure and the Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge ("Scoping Memo") issued in this proceeding on May 17, 2012.

I. INTRODUCTION

Scenario planning workshops were held by the Commission's Energy Division on April 11 and 12 and on May 17, 2012 for the purpose of presenting and discussing Energy Division's Straw Proposal for LTPP Standard Planning Assumptions. EnerNOC attended and participated in the workshops held on April 11 and 12.

On May 23, 2012, Energy Division distributed a Straw Proposal "Comment Template." Parties were directed to use and include this template in their comments due today. In particular, Energy Division asked parties to provide the following information in completing the template:

> "To the extent possible, comments should indicate if: A) the assumption is appropriate; B) if not, what assumption is appropriate including providing data

> sources and methods; C) if the assumptions can be in any way consolidated (e.g. recommend only two assumptions for energy efficiency, rather than three) or if they need to be expanded. To the extent that an issue needs to be handled in another track or time of the proceeding, please indicate that briefly."[1]

EnerNOC has reviewed the template and provided input as relevant to its concerns. That template is attached hereto as Appendix A. In doing so, EnerNOC focused on the assumptions for demand response, on both the supply and demand sides. There are several issues to which EnerNOC has not provided a response. EnerNOC may respond to other parties' comments in reply. The following section provides an overview and explanation of EnerNOC's responses.

II.
THE ASSUMPTONS FOR DEMAND RESPONSE ARE UNDERSTATED AND MAY LEAD TO EXCESS PROCUREMENT

EnerNOC has reviewed the assumptions contained in the Straw Proposal for use in conducting an analysis of resource needs in this proceeding through 2022 and beyond. EnerNOC has concluded that these assumptions are overly conservative, will understate demand response contributions, and, in turn, overstate new resources needs. Therefore, EnerNOC proposes that the assumptions for both supply and demand-side demand response resources be revised as described below and reflected in its responses in the template, attached and incorporated by reference hereto as Appendix A.

In conducting its review, EnerNOC used the same sources of data used by the Energy Division, which include the California Energy Commission's (CEC's) Revised 2011 California Energy Demand Forecast (2011 Revised CED) and the ex ante load impact protocol projections submitted by San Diego Gas & Electric Company (SDG&E) on May 23, 2012, relative to statewide and aggregator-managed programs (Ex Ante LOIP Report). In addition, EnerNOC

[1] Energy Division Comment Template, at p. 1.

reviewed the monthly load impact reports filed by the investor-owned utilities (IOUs) and their Smart Grid Deployment Plan applications (A.11-06-006, et. al.).

It is vitally important that the assumptions used for demand-side resources, and other technologies, are consistent with Commission policies, especially the loading order. To do otherwise would result in planning that is inconsistent with stated Commission policy, thereby undermining those very policies, creating inefficient, duplicative investments, and placing unnecessary burdens on ratepayers. EnerNOC's concern with the assumptions for demand response resources goes to that very issue of inconsistent treatment as between word (Commission Policy) and deed (long-term resource planning assumptions). Therefore, EnerNOC recommends that the mid-range estimate for non-event based demand response would be 10% above current levels and a reasonable amount of event-based demand response would be at least 5% of peak demand, as demand increases over time.

A. NON-EVENT BASED DEMAND RESPONSE

The assumption used in the Straw Proposal for Non-Event Based Demand Response was the same as the 2011 Revised CED. Non-event based demand response is referred to in the 2011 Revised CED as non-dispatchable demand response. Either term refers to programs that send pricing signals to customers and customers can choose whether or not to modify their behavior in response. The 2011 Revised CED states that it expects non-dispatchable demand response to grow over time, but it has not been able to quantify to what extent. Further, the 2011 Revised CED states that estimates were provided by both Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) of 20 MW each.

However, these estimates were not included in the report. Therefore, the 2011 Revised CED assumes no increase in non-dispatchable demand through 2022 as the mid-range assumptions with plus or minus 10% deviation on either side for the high and low assumptions respectively.[2] EnerNOC suggests a reasonable estimation of the potential for increases in non-event based demand response would be 10% above current levels as the mid-range scenario.

While an estimate may be difficult to quantify, assuming no growth in non-dispatchable demand response for the next 10 years seems to be overly conservative for the following reasons:

1. At present, only customers above 200 kW are exposed to either critical peak pricing (CPP) or peak-day pricing (PDP) tariffs as the default tariff. There are plans to increase the exposure of more customers to default CPP or PDP tariffs over time. In fact, PG&E in its current Rate Design Window (R.09-02-022) has made such a proposal.[3] While there may be concerns as to how to manage customer exposure to such tariffs, the policy direction is clear. Therefore, assuming no increase in non-dispatchable demand response as these tariffs are implemented seems to be a very conservative assumption and should be the "low" scenario, as opposed to the mid-range or most likely scenario.
2. The IOUs will be sending pricing information to customers, including current rate information, usage and cost (wholesale pricing) information on at least a daily basis as ordered in D.11-07-056[4] and will also conduct pilots for sending real-time, or near real-time pricing information. The intent is not only to inform customers of changes in price and cost, but to allow customers to modify their own usage in relation to those signals. Access to information, including comparative information with customers in a peer group, has been shown to reduce consumption by anywhere from 5-10%. With data access availability, such information presentation will be more widespread, giving customers more options to adjust their energy consumption.

With these known changes on the horizon, EnerNOC believes it is important to capture the potential increases in non-event based or non-dispatchable demand response as a realistic mid-range potential. While an exact calculation of that effect may be difficult, it is definitely greater than zero. Therefore, a reasonable estimation of the potential would be 10% above

[2] Revised 2011 California Energy Demand Forecast at p. 33.
[3] PG&E has also filed a Petition for Modification of D.11-11-008.
[4] D.11-07-056, Ordering Paragraphs 5, 6, and 10.

current levels. The high scenario being 10% above the mid-range scenario and the low scenario would be at current levels.

B. EVENT-BASED DEMAND RESPONSE

The Straw Proposal uses the ex ante load impact protocols (Ex Ante LOIP Report) for purposes of estimating future event-based, or dispatchable demand response, for the mid-range scenario. EnerNOC is again concerned that the use of this report will understate future demand response contributions for the following, several reasons.

1. Low to No Growth Assumptions. In reviewing the state-wide programs and aggregator managed programs, the assumptions for growth between 2014 and 2022 are either zero or 1-2% over an 8-year period.[5] Growth in demand response programs over this period should be commensurate with the growth in peak demand on the system. Otherwise, demand response will not be a priority resource, but will actually be atrophying. Further, there are many reasons to believe that demand response will be expanding over this period of time.
2. No Estimation of Demand Response Growth as a Result of Smart Grid Investments. The Straw Proposal ignores increased demand response as a result of Smart Grid Investments. In the IOUs' Smart Grid Deployment Plan Applications (A.11-06-006, et. al.), there is clearly an expectation of increased demand response and energy efficiency as a result of those investments. For example, SCE projects that it will have 1900 MW of demand response by 2014 and an additional 1,000 MW of AMI-enabled demand response by 2017 and a corresponding 250,000 MWh/year of energy savings by 2014.[6] SCE's most recent monthly load impact report, submitted on May 21, 2012, reflects a total of 1,500 MW of demand response. So, by 2017, SCE seems to be saying it will nearly have doubled its demand response capacity as a result of Smart Grid investments. PG&E has stated that they would avoid between $600 million and $1.4 billion in procurement costs

[5] See, Appendix A hereto, at pp. 8-9.
[6] SCE Smart Grid Deployment Plan Application (A.) 11-07-001, at p. 9.

over their plan period.[7] These avoided costs surely included expected increases in demand response and energy efficiency.

3. Renewable Integration. Current discussions relative to flexible capacity needs are focused on generation resources. However, demand response can surely provide balancing capabilities faster and more cost-effectively than traditional generation. Demand response is increasingly being utilized for that purpose in various markets, including PJM and ERCOT.

4. Wholesale Market Integration. The success of integrating existing dispatchable demand response into the wholesale market is yet to be seen. However, at a minimum, wholesale market integration provides an opportunity to expand the types of services that DR can provide, including ancillary services.

EnerNOC suggests that dispatchable demand response be assumed to represent 5% of peak demand, consistent with Commission Policy, and an assumption for growth based upon Smart Grid investments, consistent with the IOU's Smart Grid Deployment Plans.

III.
CONCLUSION

The Straw Proposal underestimates both the contributions of non-dispatchable and dispatchable demand response by assuming no, or very modest, growth over the forecast period from current levels. EnerNOC does not believe that assumption should be the basis for the mid-range scenario, but is more representative of the low scenario.

In this regard, various factors are likely to increase demand response penetration from now until 2022, including smart grid deployment, access to information, including pricing information and increased services. Automation will also, in the case of programmable controllable thermostats, increase demand response above current levels. Additionally, exposure of customers to CPP or PDP will either increase non-dispatchable demand response, or

[7] PG&E Smart Grid Deployment Plan Application (A.) 11-06-029, at p. 8.

customers will seek ways to actively manage their demand through dispatchable programs. As such, EnerNOC suggests that a 10% increase in non-dispatchable demand response above current levels be used for the mid-range scenario and a 5% of peak demand be used as a basis for dispatchable demand response, with some adjustment to incorporate smart grid deployment gains.

Respectfully submitted,

May 31, 2012

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APPENDIX A

ENERNOC, INC.
COMPLETED STRAW PROPOSAL COMMENT TEMPLATE

For issues or topics that are not addressed at this time, EnerNOC reserves the right to address those issues in Reply Comments. Where that is the case, the reference "Reserve for Reply Comments" is used.

General

1. Guiding Principles

EnerNOC has some concern with the stated guiding principles along with the problem statement that precedes the guiding principles. The problem statement and the guiding principles state a need to maintain reliability at the lowest cost for ratepayers, both of which are important and necessary aspects of long-term planning exercises. However, neither the problem statement nor the guiding principles state the desire to maintain reliability at the least cost while implementing the state's energy policies for meeting renewable resource requirements, demand response and energy efficiency goals and greenhouse gas reduction policies, such as distributed generation, plug-in hybrid electric vehicles, storage or smart technologies. Reliability and least-cost planning must incorporate these energy policy objectives at the core of the planning process. If it is not clear from the problem statement or the guiding principles that the State's energy policy objectives are central to the assumptions for long-term planning scenario analyses, then it is even less clear when one reviews the assumptions for the components parts. In particular, EnerNOC is proposing alternative assumptions for both the Energy Efficiency and Demand Response sections.

Guiding Principle (A) states that the analysis should take a "realistic view of policy-driven resource additions in order to ensure reliability of electric service and track progress toward resource policy goals."[1] Realistic assessments are important to give credence to the analysis results. However, "realistic" assessments should be consistent with Commission or State policy objectives, laws or initiatives and not be revisionist in nature so as to undermine those policies, laws or initiatives.

Guiding Principle (D) states that (S)cenarios should inform whether substantial new investment in transmission and flexible resources would be needed to reliably integrate and deliver new resources to loads.[2] The analysis may only show that investment in flexible resources or transmission are needed to reliably integrate new resources, but it should not designate the types of resources that may provide those new services. In other words, the output from the analysis should be technology neutral. Demand resources, storage, PHEVs or other technologies may be useful in integrating resources alongside traditional, fossil-fuel based resources, dependent upon how those products are defined.

2. Planning area and planning period

<u>Reserve for Reply Comments</u>

[1] LTPP Straw Proposal, at p. vii.
[2] <u>Id</u>.

Demand-side Assumptions

3. Economic & Demographic assumptions

Reserve for Reply Comments

4. **Load Forecast**

Reserve for Reply Comments

a. Is the most recent revised demand forecast appropriate to use in the absence of a recent adopted demand forecast?

Reserve for Reply Comments

5. **Incremental Energy Efficiency**

Note: Some impacts of energy efficiency are embedded into the Energy Commission's IEPR forecast. The savings here are above and beyond those levels.

Reserve for Reply Comments

6. **Non Event-Based Demand Response**

Note: Most Demand Response is accounted for on the supply-side via Event-Based programs.

The Straw Proposal proposes to use the same forecast as is contained in the California Energy Commission's (CEC's) Revised 2011 California Energy Demand (Revised 2011 CED). Event-based demand response, or dispatchable demand response, is treated as a supply resource and is, therefore, not included in the forecast.[3] Demand response programs which are based on sending economic signals for customer response are considered non event-based or non-dispatchable programs. EnerNOC assumes that these non event-based or non-dispatchable demand response programs include critical peak-day pricing (CPP) and peak-day pricing (PDP) programs. The Revised 2011 CED states that it expects participation in these programs to expand over time, but that the conversations with PG&E and SCE only revealed an additional 20 MW of additional capacity each, which the report excluded.

To date, only customers above 200 kW have had CPP or PDP pricing programs implemented as default tariffs. However, the IOUs are in the process of implementing CPP or PDP pricing programs for commercial and industrial customers down to 20 kW. It is also possible that residential customers may have some form of PDP/CPP pricing after 2014. It is hard for EnerNOC to believe that expanding customer exposure to PDP/CPP from where it is today, large commercial and industrial customers, to small and medium commercial and industrial customers and ultimately to residential customers (through 2022) will only produce 20 MW of additional response per utility in a non-event based demand response program or that those rate schedules would not encourage customers to participate in other event-based demand response programs so as to actively manage their exposure to high price events. However, this additional potential is not captured in either the non-event based analysis or the event-based analysis.

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[3] Revised 2011 California Energy Demand Forecast, at p. 33.

7. Incremental small photovolatics (demand-side)

Reserve for Reply Comments

8. **Incremental combined heat and power (demand-side)**

Note: CHP is split between demand-side and supply-side. See supply-side values for incremental CHP assumed exporting to the grid.

a. What capacity factor is appropriate to use?

Reserve for Reply Comments

9. Traditionally, local area and other assessments utilizing a higher peak forecast have been based on a middle forecast for energy and peak. If this should be changed, please explain why.

Reserve for Reply Comments

10. Are there any significant demand-side assumptions that have been missed? If so please identify, provide sources, and the MW and GWh magnitude and likelihood.

This analysis seems to make no assumptions for either PHEV as increasing demand in off-peak periods, when the wind is blowing, or to access the batter y to provide short-term support for system fluctuations. Further, the analysis doesn't contemplate any storage deployment for similar purposes. Lastly, the report does not contemplate any behavioral changes, at homes or business, related to smart grid deployment efforts, access to smart meter information or for automation. The smart grid deployment plans issued by the utilities in June/July 2011 (A.11-06-006) indicate that the IOUs expect to increase energy efficiency and demand response as a result of customers having access to data or employing automation in response to signals that may be sent by the utilities, CAISO or third parties. There are HAN deployment initiatives, backhaul data access initiatives and GreenButton initiatives that are permitting more customer services for demand management than previously available. The utilities expect to install programmable controllable thermostats that will reduce air conditioning demand during summer days. The utilities have provided estimates of avoided procurement costs over a multi-year period. In addition, SCE has indicated that it intends to increase demand response for small to medium commercial and industrial customers, through 2015 by 500 MW. It would be incongruous to develop resource needs for the next 10 to 20 years without incorporating the demand-side savings that could be realized through smart technologies. Lastly, there is an effort underway to incorporate demand response into the wholesale market. This would be dispatchable demand response, and will be discussed in that section of this template.

11. Other comments on demand-side assumptions.

Reserve for Reply Comments

Supply-side Assumptions

12. Should all resources be accounted for by their NQC or a forecast of NQC?

For demand resources, load impact protocols have been determined to be the basis of calculating qualifying capacity.

13. What year and data source should be used for variable resources' production profiles?
<u>Reserve for Reply Comments</u>

14. How should transmission capacity be considered?
<u>Reserve for Reply Comments</u>

15. Should all "known" and "planned" (non-RPS) resources be used in all supply-side scenarios?
<u>Reserve for Reply Comments</u>

a. **Are the definitions of "known" and "planned" clear?**
Note: At the workshop, "planned" having a contract in place was clarified to mean "approved contract by the appropriate entity" (e.g. Muni approved or CPUC approved). Do you support this clarification?
<u>Reserve for Reply Comments</u>

16. **Deliverability**
Note: The previous assumption of deliverability assumed all resources were deliverable unless otherwise noted.
<u>Reserve for Reply Comments</u>

a. Are any changes to the definition of future resources considered deliverable warranted?
<u>Reserve for Reply Comments</u>

b. How should information from other sources, such as distribution resource deliverability be incorporated?
<u>Reserve for Reply Comments</u>

17. What additional information is needed for resource locations?
<u>Reserve for Reply Comments</u>

18. Event-Based Demand Response

The Straw Proposal suggests using the recently filed Load Impact reports as the basis for estimating event-based demand response as the mid-range scenario with a sensitivity of plus or minus 10% on either side for the high and low range assumptions.

EnerNOC has reviewed the ex post and ex ante draft load impact report submitted by SDG&E on March 23, 2012[4], and is concerned that use of the ex ante load impact results as the basis for the mid-range scenario, will actually understate demand response contributions that are likely to occur over the planning timeframe. This Report, developed by Freeman Sullivan, presents the results of the ex post load impacts for 2011 and calculates the ex ante load impacts for statewide aggregator managed programs for 2012-2022. The programs evaluated in this Report are PG&E's aggregator managed programs (AMP), SCE's demand response capacity contracts (DRCC) and each utility's managed statewide program, such as capacity bidding programs (CBP) and demand bidding program (DBP).

The Report's ex post results by program by utility are indicated in the **following table**:

[4] 2011 Load Impact Evaluation of California's Aggregator Demand Response Programs Ex Post Results. http://sdge.com/node/742

PG&E[5]	CBP	2012	2013	2014-2022
	DA	13.8	15.9	16.0-18.4
	DO	18.4	21.1	21.3-24.8
	Total	32.2	37.0	37.3-43.5
	% Change		15%	1-2%

PG&E[6]	AMP	2012	2013	2014-2022
	DA	44.1	44.1	44.1
	DO	154.5	154.5	154.5
	Total	198.7	198.7	198.7

SCE[7]	CBP	2012	2013	2014-2022
	DA	5.4	5.7	5.7
	DO	20.9	22.1	22.1
	Total	26.3	27.8	27.8

SCE[8]	DRCC	2012	2013	2014-2022
	DA	13.5	13.5	13.5
	DO	153.5	168.9	185.8
	Total	167.1	182.4	199.3
	Percent Change		9%	9%

SDG&E[9]	CBP	2012	2013	2014-2022
	DA	12.7	13.5	14.2
	DO	12.3	12.9	13.6
	Total	25	26.4	27.8

PG&E's AMP reflects no growth from 2012 through 2022. PG&E's CBP reflects 15% growth from 2012 to 2013 and then nominal growth (1-2%) through2022. SCE's DRCC reflects 9% growth between 2012 and 2013 and then 9% growth either between 2013 and 2014, with no growth between 2015 and 2022 or about 1% average over all years 2014 through 2022. All of these growth projections are modest, with the exception of SCE's 2012-2013 growth. Growth in CBP for all three utilities is modest.

There are several reasons why these growth projections, outside of 2012-2013 are more representative of a "low" scenario than a mid-range scenario.

[5] Report, at p. 57.
[6] Report, at p. 53.
[7] Report, at p. 64.
[8] Report, at p. 61.
[9] Report, at p. 67.

For one thing, the CPUC is in the process of integrating demand response into the wholesale market. There are legitimate questions as to whether or not wholesale market participation under the existing market structure will actually expand demand response participation beyond existing levels. However, if the DR is integrated into the wholesale market, successfully, DR will still be a supply-side resource either under existing utility contracts or wholesale market participation. The wholesale market could provide additional opportunities for ancillary service participation as well as, potentially, flexible capacity or ramping opportunities. DR can be used for balancing renewable intermittency, as is done in other parts of the country. Automation of demand response is increasing through automated DR incentives offered through the utilities. Smart grid presents other opportunities for expanding both demand response and energy efficiency. In SCE's Smart Grid Deployment Plan Application (A.11-06-006, et. al.), SCE projects that it will have 1,900 MW of demand response by 2014 and an additional 1,000 MW of AMI-enabled DR by 2017.[10] SCE also projects 250,000 MWh/year of energy savings by 2014. SCE currently has about 1,500 MW of DR capacity as of the last monthly report filed on May 21, 2012 in R.08-06-001. PG&E in its smart grid deployment plan application projects avoided procurements costs of between $600 million to $1.4 billion over the analysis period. This means that DR and EE gains would offset the cost to procure energy or capacity.[11]

In light of the ability of DR to integrate renewable, technology gains for DR to provide ancillary services or other forms of system support, increasing peak-day capacity exposure of smaller customers and the need to manage that exposure, integration into the wholesale market, it seems to be entirely inconsistent to assume no growth in either dispatchable or non-dispatchable demand response resources over the study period, through 2022, without having to accept as a premise a complete discount of Commission policies. The consequence of these low-biased assumptions is to reinforce the need for traditional fossil-fueled resources. This is a continuing concern of EnerNOC's that the CPUC's policy directives do not jibe with the assumptions used for resource or transmission planning in either the LTPP or the CAISO's analyses. It creates the likelihood that duplicative resources will be acquired, the system will be over-supplied and the value of all resources will be diminished.

In the Energy Action Plan II, and further reiterated in numerous Commission Decisions, most recently in D.12-04-045, demand response and energy efficiency are at the top of the loading order and are a priority resources, so long as they are cost-effective, over all other resources. The Straw Proposal does not seem to incorporate that policy into its planning assumptions.

19. Incremental combined heat and power (supply-side)

Note: CHP is split between demand-side and supply-side. See demand-side values for incremental CHP assumed behind the meter.

Reserve for Reply Comments

a. What capacity factor is appropriate to use?

Reserve for Reply Comments

[10] SCE's Smart Grid Deployment Plan Application (A.)11-07-001 , Appendix A, at p. 9.
[11] PG&E's Smart Grid Deployment Plan Application (A.)11-06-029, Appendix A, at p. 8.

20. Renewable Resources

<u>Reserve for Reply Comments – Section 20 and all subparts (a) – (f)</u>

a. **Establishing the 33% RPS infrastructure target via the LTPP, understanding that other requirements may also need a similar calculation within the RPS proceeding.**

b. **Establishing the RPS supply (i.e. the "highly likely resources") in the RPS proceeding.**

c. **Base Portfolio**

d. **High DG Portfolio**

e. **Sensitivities**

f. Long-term Target

21. Retirements

<u>Reserve for Reply Comments</u>

a. How many retirement assumption combinations are needed? If more than one, please list the top two most important retirement assumptions to consider sensitivities on.

<u>Reserve for Reply Comments</u>

22. Are there any significant supply-side assumptions that have been missed? If so please identify, provide sources, and the MW and GWh (if appropriate) magnitude and likelihood.

<u>Reserve for Reply Comments</u>

23. What is a reasonable number of overall scenarios for <u>supply-side</u> assumptions? What is the purpose behind having that number of scenarios?

<u>Reserve for Reply Comments</u>

24. Other comments on supply-side assumptions.

<u>Reserve for Reply Comments</u>

Allocation Methodologies

If another allocation methodology is appropriate, parties are encouraged to provide it. It is also appropriate to suggest alternative methodologies to be used in a subsequent LTPP if they may require significant development.

25. Energy Efficiency

Reserve for Reply Comments

26. Demand Response

Reserve for Reply Comments

27. Other methodologies for assigning resources to busbars.

Reserve for Reply Comments

Other

28. What is a reasonable number of total scenarios + sensitivities to consider?

Reserve for Reply Comments

- **a. Briefly describe the scenarios and sensitivities that are most important to consider. Please refer to the assumptions discussed above to describe and explain this recommendation.**

  Reserve for Reply Comments

29. Any other comments.

Reserve for Reply Comments