1	Multiple potential Respondents have noted that dates within the South Fork RFP, for specific events, are not consistent. These events include Proposal Submittal Date and the Webex Date.	The RFP has been edited to reflect consistent dates for these and all events. The RFP has been posted on the PSEG LI and LIPA websites as Revision 1.
2	We have a question in regard to the requirements outlined in Section B7.1 – Site Continuous Power Capacity: Can PSEG-LI provide an estimated frequency of disruption to the transmission system (e.g., average number of interruptions per year) that would require Power Production resources as defined in Appendix B to provide up to 60 hours of power output at the East Hampton substation and 40 hours at the Montauk substation? The frequency of transmission system disruptions will greatly impact the cost and feasibility of some potential power production resources. For example, the solution that may make sense if transmission disruption is likely only every few years is very different from a solution that needs to provide this support weekly or even monthly.	There is no way to predict when an outage will occur. Whether the transmission event is likely or unlikely, a potential resource still needs to be designed in such a way to conform to the technical requirements set forth in the RFP. There are multiple contingencies affecting the South Fork, and due to the radial nature of the system, if there is a prolonged outage for any reason, we would expect the proposed device to be able to provide system support. That said, the 60 and 40 hours referenced in the RFP are not constant durational values that proposed devices need to output their rated capacity- they are multipliers to determine the required energy a device will need to produce without recharging from the system. For example, should a 20 MW device be proposed at East Hampton, it should be able to provide 1200 MWh (20 MW x 60 Hours) of support without recharging from the system.
3	When will I know when new documents are posted to the website? Is there any type of Alert System?	It is up to the potential Respondents to check the RFP website occasionally. If PSEG LI established an “Alert System” via a distribution list or some similar mechanism and some entities were inadvertently left off the list them this may be perceived and giving some entities an unfair advantage.
4	If power production equipment connected to the distribution system is an option per Appendix A, and traditional power generating equipment is proposed, will it be a requirement that the resource be dispatched in accordance with the operating modes described in Appendix B (Standby and Transmission Support Modes)? Is there a maximum unit size to maintain security constrained dispatch? Is the maximum unit size of the proposed resource different depending on which side of Boundary A the resource is located? What is the maximum and minimum size Power Production Resources for the Southampton substation? Are multiple or single units acceptable for Southampton?	No. All specifications set forth in Appendix B are technically specified for those proposals wishing to connect to the transmission system at East Hampton and/or Montauk only. Devices wishing to connect to the distribution system will need to follow Appendix A and the additional criteria documents specified in section A2 of the RFP. With respect to Southampton, the maximum size generating unit would be approximately 10 MW based on feeder rating assuming it’s a direct connection to the station. If attached to an existing (non-dedicated) feeder, the maximum amount would depend on existing resources already connected to the feeder, load on feeder, technology and location of proposed resource on the feeder.

5	Per Appendix B, section B6 Operating Modes, please describe how the trigger signal will function, for example, will there be digital signals for start/stop, and analog signals to dispatch and ramp the resource?	The trigger is proposed to be a dry relay contact at the LIPA substation, to be provided by PSEG LI. The trigger will be initiated by either or both automatic means and manual initiation by the System Operator. If this trigger contact is opened after being closed, the resource will remain at the power level at which it is operating at the time the contact is opened (either the pre-determined Transmission Support Mode power level, or the power level point on the ramp-up to this Transmission Support Mode level, or any subsequent re-dispatch, if the contact opening should occur during ramping).
6	If the power production resource is going to operate in one of the 3 Standby Modes, in paragraph B10.4.2, should there be desired System Operator MW signal inputs to the RTU so that resource can be dispatched in a manner that eliminates T&D overloads?	If the resource is outputting power to eliminate T&D overloads at any given time, by definition, it is in Transmission support mode. The standby option mode 1 is essentially same as the transmission support mode since the resource will be dispatched based on transmission constraints. For standby option 2 and 3, there will be a trigger signal which could be either through automatic detection of a fault or through the initiation by the system operator through SCADA. For the latter where the initiation is through system operator, there will be desired control signal from System Operator to transition to transmission support mode. If the proposed resources allow certain MW settings, then the system operator will utilize it as needed through control signals from SCADA . This is based on the capability of the specific resources.
7	In Appendix B (paragraph B6.1.2 and B6.1.3, Standby Mode Option 2 and 3), will the resource be dispatched on and off similar to Option 1? Is the only difference between Option 1 and Options 2/3 that the resource needs to capable to ramp to rated output within 5 minutes? Or do these options require that the resource be synchronized to the system and available to ramp to full load in five minutes for the entire duration of potential T&D overload? Is it acceptable for a proposed resource to ramp to rated capacity in 10 minutes?	Option 1 is the traditional security constrained dispatch where the device will be dispatched on or off, to output levels which avoid overloads in the event of the worst-case transmission outage contingency, with no fast-ramping capability. This option will potentially incur the most runtime for the device. Options 2 and 3, both rely on ramping within a 5 min timeframe (10 minutes would be unacceptable). Option 2 has a 0 MW initial output and Option 3 has a non-zero output. It is expected that the device will provide full output equal to the pre-determined Transmission Support Mode value or any subsequent re-dispatch within the rated capability of the resource, continuing for as long as the trigger value is "TRUE" (trigger relay contacts closed). For Option 2, the resource does not necessarily have to remain synchronized while in Standby, as long as synchronization and ramp-up to the rated value can be accomplished in five minutes or less. All resources, including resources normally operated in Standby Options 2 or 3, may be required at any time to operate in a security-constrained dispatch mode at PSEG Long Island's discretion.

8	For Standby Modes 2 and 3 transitions to the Transmission Support Mode, how is the pre-determined power level calculated?	It is expected that for most cases the "pre-determined" power level will be the full capability of the the resource that would be needed for transmission support mode. The pre- determined power level will be calculated based on the forecasted South Fork load minus the delivery capability of the T&D system, derated by the most constrained potential transmission outage. The RFP states it as "pre-determined" rather than full output for the reason that there may be the situation where the unit would be useful for multiple contingencies, each requiring a different minimum level of output. If the unit were put into service to cover the lesser requirement, it should remain available to step to the greater requirement if a trigger were to occur for that greater requirement.
9	For fuel based generation, can a dedicated fuel transportation supply plan be used in lieu of the five day storage requirement?	Yes, if assurances can be exhibited that the fuel supply is solid and continuous operation can be maintained.
10	On page 4 of the RFP, it says that power production connected to distribution feeders is detailed in Appendix A. I did not see any information in Appendix A regarding this option. Please clarify, thanks.	See answer to Question 4.
11	RFP page 39, par 4.8—Request for T&D System Data – states that PSEGLI will provide a load flow, contingency list and one line diagram around an electrical bus at a proposed interconnection point. A statement on slide #7 of the webex specifies that only one connection is available at each of the East Hampton and Montauk substations. We are interested in knowing what is the maximum MW capacity available to be connected at each substation, and any other information that he can be provided about these points.	Transmission connections are limited to East Hampton and Montauk. Distribution connections can be more widely available at other stations and are dependent where a developer wishes to connect. Generally speaking a connection to an existing substation feeder is limited to 2 MW whereas a connection via a dedicated feeder is 10 MW maximum. See also response to Question 4.
12	Our understanding is that there is a 350 psi main that ends at South Hampton, and thereafter, the main drops to a lower pressure. Is there a description of the natural gas infrastructure downstream and spare capacity? Are there any upgrades anticipated in the near future? It is important to have this understanding to be able to design a project that has certainty around its fuel supply.	Questions regarding the natural gas system infrastructure must be sent to National Grid.
13	RFP Section 2.7. Conditions Precedent for Agreement states that for proposed projects subject to review under the New York State SEQRA, LIPA is prohibited from executing Agreements until the SEQRA process is complete. Please clarify LIPA Agreement Conditions Precedent for individual and/or portfolio Power Production Resource responses/Offers to Appendix B that will be exceeding the 25MWAC New York State Article 10 threshold that supersedes SEQRA.	For a proposed project subject to Article 10 of the New York Public Service Law, a condition precedent to the PPA becoming effective is that the proposer must receive a certificate of environmental compatibility and public need from the New York State Board on Electric Generation Siting and the Environment.
14	Page 6 of the RFP states that "only one award will be made per technology class per customer segment". Can you elaborate on this statement, (beyond the issue of preventing the same resource from being counted twice). For example, we control non-central AC loads from many sources, such as window ACs, web-enabled ACs, PTACs and split units, for residential, small business and MUSH market customers. So it is a question of awarding a vendor for multiple technologies for multiple customer classes.	This requirement exists as stated to:1) preclude Proposers from offering proposlas that may target the same resources and 2) to utilize those proposals that offer the longest duration of load reduction.

15	When will we know the "DER platform" scope, timing and requirements, as integration with that new platform has to be costed out in our proposal.	The DER platform requirements will follow the latest version of the open ADR Alliance requirements. Please follow the specifications within the open ADR protocol in order to be able to properly integrate with the future PSEG LI DER platform.
16	Will special consideration be given to those vendors that can provide load reductions earlier than your listed starting requirements?	No special consideration will be given; however, page 14 indicates that in the event of the proposal of an early COD, separate pricing should be provided.
17	1. Is the Distributed Energy Resource (DER) Platform already selected? 2. If the DER Platform is already selected, to what extent can we depend on it to balance energy commitments from our aggregated assets to minimize our possible penalties from our individual assets? 3. If the DER Platform is already selected, to what extent can the platform be used to transact energy exchange between assets on the feeder lines? 4. If the DER Platform is not already selected can we include a platform in our proposal? Do we then need to include its cost in our in our proposed cost/kW/ kWh, or quote it separately?	1. No. The DER platform has not been finalized. The DER platform requirements will follow the latest version of the open ADR Alliance requirements. Please follow the specifications within the open ADR protocol in order to be able to properly integrate with the future PSEG LI DER platform. 2-3. N/A 4. Do not include a DER platform bid as part of the SF RFP.
18	1. We may need to access smart meters and their data. Are smart meters already selected? 2. If smart meters are already selected, do they have RS232, RS485, and/or WIFI ports? 3. If smart meters are already selected, what memory and microprocessor resources are available for interface code and algorithms? 4. If existing smart meters are not capable of performing certain functions, do we need to include the cost of a communications architecture into our proposed cost/kW/ kWh, or quote it separately? 5. If smart meters are already selected, do they include relays for remote disconnect?	1. Smart meters are not selected, and will not be available in any meaningful capacity on the South Fork. 2-3) N/A 4) Please include the communications architecture as part of the SF RFP bid. 5) N/A
19	If we enable Demand Response for such things as load shedding, thereby enabling one to implement such activity for little incremental cost for customers using our equipment, will such reductions be rejected because of a potential overlap with other companies proposing DR in the same region?	Reductions will not be rejected unless it is determined that the same customers are involved, not simply for the same region.
20	If we sell equipment to a customer and the equipment is used to meet the needs of their own load, does the total load reduction count as a load reduction resource? Even if it is not "callable"?	All resources installed behind the customer meter at their facilities must be verifiable load reduction resources in order meet the needs of the SF RFP.
21	Is there any limitation to the production of energy by a customer above the need of their own load?	There is no set limit to the energy production by an end use customer as long as all load is verifiable, and can be accepted (based on location and size of the load) into the electric grid.
22	1. Will a net metering plan be available over the next 20 years? 2. If there is no guarantee of a net metering plan over the next 20 years, can the cost of excess energy producing resources be segregated such that the incremental cost is not incurred by the customer who owns those resources? For example, a customer may be willing to allow their roof or land to be used for resources above their own needs, but will not able to properly monetize a return on the incremental investment.	1. No. A net metering 20 year plan will not be available. 2. Respondents are to provide their bids in accordance with the bid details and information included in the RFP. PSEG LI does not provide the mechanism or direction on how best to structure financing or costs for the purposes of this RFP.
23	Should we include budget for the Operations and Management of all assets in our proposal, including those behind the meter and on the utility side?	Yes, Respondents should include budget for the Operations and Management of all assets in their proposals, including those behind the meter and on the utility side.

24	Do all aggregated resources need to be owned and financed by us and governed under PPA agreements with end customers, or can we also sell to customers under programs such as NY PACE and include those resources in our aggregation?	Respondents must be able to be proven to be under the control of the aggregator. PSEG Long Island has not set forth any requirements regarding ownership or financing arrangements.
25	4. Will PSEG-LI establish the capacity of a power production resource proposed in this RFP using the same metrics as the NYISO's methodology for establishing a generator's UCAP? If not, please explain the difference between PSEG-LI's methodology for establishing the quantity of capacity and those of the NYISO's UCAP program.	Yes
26	5. To what extent will PSEG-LI consider local support for or opposition to proposed projects?	The Qualitative Evaluation Criteria includes "Community Acceptance," so this aspect will be considered in Phase 2 and Phase 3 of the selection process.
27	6. Will PSEG-LI give any preference to proposals that employ renewable energy technologies over those that employ fossil-fired technologies?	No special preference will be given to renewables over fossil fuel-fired technologies.
28	7. What factors, if any, will PSEG-LI consider in evaluating renewable energy proposals that it will not consider for fossil-fired proposals?	The Quantitative and Qualitative Evaluation Criteria are the same for both renewables and fossil fuel-fired generation.
29	8. If PSEG-LI selects a renewable energy source in this RFP, will it reduce the amount of renewable energy capacity purchased in the second-half of the 280 MW renewable energy procurement?	Yes, any renewables selected for the South Fork RFP would reduce the MWs of renewables needed in the upcoming renewable RFP.
30	9. Will PSEG-LI consider the avoided cost of renewable resources procured in the second-half of the 280 MW renewable energy RFP when evaluating a renewable energy resource proposed in this RFP?	Yes, PSEG-LI will consider the avoided cost of renewable resources procured in the second-half of the 280 MW renewable energy RFP when evaluating a renewable energy resource proposed in this RFP.
31	10. When will the draft PPA's be available for review?	PSEG LI is in the process of modifying existing PPAs to accommodate this type of procurement. Currently the planned posting date of the PPA is at the end of September. A Service Contract for Load Reduction is expected to be posted earlier.
32	Is pipeline natural gas is available on the South Fork? Specifically, any information you can provide related to the volume and pressure of gas at the proposed project sites is greatly appreciated.	Questions regarding the natural gas system infrastructure must be sent to National Grid.
33	Does the Distributed Energy Resource need to meet FERC's requirements for a cogeneration facility under 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output, and be certified as a Qualifying Facility pursuant to 18 C.F.R. § 292.207?	No. DERs do not need to be a Qualifying Facility.
34	Are there minimum system efficiency requirements?	There are no minimum system efficiency standards set by PSEG LI within this SF RFP.
35	1.Is there a minimum / maximum MWh / rated capacity requirement for the purposes of this RFP? 2. Can you submit projects for both load reduction and power production? 3. For projects that generate environmental attributes, does the generator keep those attributes? 4. For those technologies requiring fuel, is it the expectation that the generator will supply fuel to the project or will fuel be provided by PSEG LI? 5. Will PSEG LI have any sites that they intend to provide for generators as part of this RFP or is site acquisition the responsibility of the generator?	1. See Section B7 for capacity requirements. 2. Yes 3. All renewable energy credits and / or renewable benefits are the property of LIPA. 4. Per Section B4.4, the Respondent must supply fuel. 5. Per Section B4.2, site acquisition is the responsibility of the Respondent.

36	1. Do PSEG LI's projections for peak times and loads assume any efficiency gains behind the meter or do respondents need to factor that in to their analysis? 2. Please confirm that thermal energy storage which permanently reduces air conditioning systems < 20 tons in size for commercial, industrial, and residential qualifies as a Load Reduction resource. 3. Please advise when and where the Form of Agreement will be posted as it is not currently posted in the Proposals folder. 4. Who will be able to claim the Green benefits? 5. How will submission as a Load Reduction resource affect participation in the PSEG LI EE&RE programs listed in Appendix A? 6. Please advise when PSEG LI expects to clarify whether PSEG LI will provide a single point interface software program and what, if any, DER platform is selected. 7. Please clarify/define the customer segments that awards per technology class will be based on. 8. Please clarify the requirement for aggregating smaller systems to meet the 100 kW minimum resource threshold.	1. All system peak loads and timing has included projections of efficiency reductions for the area. 2. Thermal energy storage does qualify as a load reduction resource within the parameters of the SF RFP. 3. This document is currently being developed to cover all technologies offered in this procurement and will be available as soon as practical. The target date is September 19th. 4. All renewable energy credits and / or renewable benefits are the property of LIPA. 5. Load reduction resources submitted under this SF RFP will not affect participation in the EE&RE programs listed. 6. The DER platform requirements will follow the latest version of the open ADR Alliance requirements. Please follow the specifications within the open ADR protocol in order to be able to properly integrate with the future PSEG LI DER platform. 7. All residential and non-residential customers are included in this SF RFP. 8. The 100kW minimum threshold for aggregated systems means that an aggregator has to bid and be able to deliver at least 100 kW representing the sum of relief from individual customers it is aggregating.
37	For both your small and medium commercial customer segments discussed in A1.1.2 and A1.1.3 respectively can you provide an additional breakdown of customer count by peak load range. For example of the 7,500 small commercial customers, there are XXX customers that have a peak load in the 0 to 50 KW range, YYY with peak load in the 51 – 100 KW range, ZZZ with peak load in the 101 – 150 KW range, etc.	This level of customer information is not available
38	1. What is the status of the 2 – 3 MW diesel generators in Montauk? a. Are they operational? 2. Where is the future Montauk Substation site? a. Is there LIPA property available on the site for additional facilities? b. When is the new substation to be in service and will the former substation site be available?	1. These units have been retired. 2. The future of the Montauk Substation is being discussed at this time. For the purposes of this procurement the Montauk Substation should be the targeted interconnection point, not a potential future substation. Any cost resulting from a redirected relocation in the future of interconnection from the Montauk substation to an alternate substation will be accommodated via Section 1.2.2 of the RFP

39	Power production resources will be connected to the 23 KV Montauk Substation bus. Can energy storage Load Reduction Resources be connected to the 23 KV distribution system? a. If so, how and when would a distribution circuit interconnection point be approved?	23 kV on the LIPA system is classified as transmission. Therefore, any resource wishing to connect to that voltage level would have to comply with Appendix B and connect as a power production resource. Energy storage can connect to the 23 kV but it would be classified as power production in accordance with Appendix B of the RFP and must conform to the technical specifications outlined in Appendix B.
40	Given that actual interconnections will not be able to be completed prior to RFP submittal, will respondent's answers to the interconnection information required by Section 3.2.12.6 be considered subject to change, pending the results of the interconnection process?	Yes
41	Is a digital fault recorder (3.12.2.7) required for all resources?	As per section B14.2, a Digital Fault Recorder (DFR) shall be installed at each power production resource. This is not required for those resources connecting to the distribution in accordance with Appendix A.
42	Regarding Section 3.2.13, Design Studies: a. Will design studies be required for peak shaving resources? b. When will design studies have to be done and available for review? c. When will system data be available? d. Is the NDA to be executed prior to requesting data?	a. Yes, design studies will be required b. A CRITICAL ENERGY INFRASTRUCTURE INFORMATION ("CEII") NON-DISCLOSURE AGREEMENT is now posted on the website. Please submit it to the RFP email address. c. A CRITICAL ENERGY INFRASTRUCTURE INFORMATION ("CEII") NON-DISCLOSURE AGREEMENT is now posted on the website. Please submit it to the RFP email address. d. Yes, an NDA and CEII agreements will need to be executed prior to requesting data.
43	Will overhead interconnection lines be allowed to be placed on PSEG LI poles? a. Would PSEG LI construct either overhead or underground lines?	PSEG LI does not allow third party facilities. However, what could be done is PSEG LI would place the wires on PSEG LI poles, the developer would pay for them, PSEG LI would take ownership, and the developer would pay an on-going maintenance fee.
44	Under B3., Power Production resources will be bid in the ISO by PSEG ER&T. Does this include resources owned by a third party or only those owned by PSEG LI/LIPA? a. Where do the market revenues go if third party owned? b. Would third party owned Load Reduction Resources (either in front of or behind the meter) be allowed to independently participate in NYISO markets while still meeting PSEG LI peak shaving obligations?	a) If LIPA has a contract for the capacity PSEG ER&T would do the bidding and the get the revenue. B) Non contract entities would deal with NYISO directly
45	1. If a bidder had submitted four proposals in the 2013 GS & DR RFP and spent $120,000 for those submittals will the bidder be allowed more than one submission fee waiver and/or up to $120,000 of credit in the 2015 South Fork RFP? If not, why not?	As per Section 6.0 (2) of the 2013 GS and DR RFP: "This RFP does not commit LIPA to award a contract, pay any costs associated with the preparation of a proposal, or procure or contract for any project whatsoever.LIPA reserves the right, in its sole discretion, to accept or reject any or all responses to this RFP, to negotiate with any and all Respondents susceptible of being selected for award, or to cancel this RFP in whole or in part and to pursue other resource alternatives which may include negotiating with entities that were not Respondents."

46	May the Respondent combine multiple technologies into a single Proposal?	Yes they can be combined in a single proposal as options, but separate pricing should be provided for each option so that PSEG LI can select individual option(s).
47	Must the respondent to the RFP be the entity that executes the power purchase agreement with PSEG LI/LIPA? Or can an affiliate (such as a project-specific special purpose entity) execute the power purchase agreement? Will the power purchase agreement be assignable by Seller to an affiliate of Seller without obtaining PSEG LI/LIPA prior consent?	The entity that submits the Proposal must be the same entity that signs the PPA. After the PPA is signed, the project can be assigned and this request will not be unreasonably withheld.
48	Section 2.5 notes that pricing and terms must be firm through March 31, 2017. However, on page 8 it states that firm pricing is required thru September 30th 2017. Please clarify.	The correct date is September 30, 2017. This will be documented in a revision to the RFP which will be issued prior to September 30, 2015.
49	If there is a change in regulation or law that directly impacts the bid prior to selection or prior to execution of the contract, how will PSEG LI/LIPA address the change issue?	Seller shall be responsible for and pay for all additional costs resulting from a Change in Law affecting or arising on Seller's side of the Delivery Point. Buyer shall be responsible for and pay for all additional costs resulting from a Change in Law affecting or arising on Buyer's side of the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of Products to Buyer and are, therefore, the responsibility of Seller).“Change in Law” means the enactment, adoption, promulgation, modification, suspension, repeal, or judicial determination, after the execution date of PPA, by any Governmental Authority of any Legal Requirement that materially affects the costs associated with a Party's performance of its obligations hereunder or its ability to perform its obligations hereunder. For the avoidance of doubt, neither of the following shall be considered a Change in Law: (a) a new Legal Requirement imposed on the Project that is not applicable generally to electric generating facilities, or (b) a change in interpretation or enforcement of any existing Legal Requirement.
50	Please clarify if a delayed COD is a determination by PSEG LI/LIPA or by Seller	As per Section 2.2.1, the proposal must offer pricing for a one year delay to the COD. The preferred COD is May 1st of 2017, May 1st of 2018, or May 1st of 2019.
51	Please elaborate on the section & proposal related to minority, veteran and women business ownership as well the NY VendRep System requirements	NYS has taken a strong position with respect to minority, veteran and women business ownership as well the NY VendRep System requirements. Successful bidders to this procurement will sign a PPA or a Service Contract with LIPA or PSEG LI. If a successful bidder does not comply with the aforementioned minority, veteran and women business ownership as well the NY VendRep System requirements that bidder may not be successful in the approval of those agreements by NYS government. Waivers are possible, but they are not within the control of PSEG LI nor LIPA.
52	Can the proposal be submitted via FTP or electronic copy?	As per Section 4.4, one (1) electronic copy of each Proposal (sent via CD, DVD, or flash drive) shall be submitted to PSEG Long Island. No FTP will be set up.

53	Please elaborate on the Quantitative Evaluation Criteria and process for such analysis in table 5.1	The first step of the Quantitative analysis is a levelized cost screening analysis that looks at the cost of the project and the benefits to the LIPA system. The second step is a more detailed analysis that further investigates the costs studied in step one and also the financial impact of the project with respect to its integration into that same LIPA system (i.e. system upgrades) in concert with other potential projects.
54	Please confirm and discuss the target MWs for this RFP	The target MWs for this procurement are described in Section 1.2 and pictorally in Figure 1-2.
55	Please confirm what kV interconnections fall under SGIP	DG less than 10 MW interconnecting with the distribution system via feeder. Also see answer to Question 11.
56	Please describe the limitations on interconnection at transmission level	Interconnections to the transmission system would fall under the requirements of NYISO interconnection procedures
57	Please describe any limitations on interconnection locations for load reduction resources	Interconnections would fall under the requirements of SGIP.
58	Program Specific Questions: a. Can load reduction and power production resources be aggregated into a combined portfolio as a response to the RFP? b. Are there restrictions on the services provided outside of the Service Delivery Hours by assets bid into this RFP? c. Are assets that are typically installed to permanently lower customer loads (e.g. energy efficiency) recognized as load reduction resources for the RFP? If yes, how will their Customer Baseline Load be calculated (given the definition in section A4.2)?	a. Yes they can be combined in a single proposal as options, but separate pricing should be provided for each option so that PSEG LI can select individual option(s). b. No, however, proposals will be evaluated with respect to their ability to meet the requirements of the RFP, including, but not limited to Section 1.2.1. c. Yes, assets that would generally be installed as energy efficiency program measures will be recognized as load reduction resources for this RFP. The calculation of savings would generally be expected to be in concurrence with the Technical Resource Manual provisions currently used in the Energy Efficiency Program. In the event that the PSEG Long Island TRM did not cover the asset, then the New York State TRM would be looked to. If no TRM provisions exist for the asset, the Respondent should propose the means by which savings would expect to be calculated as part of Respondents submittal.

59	Load Profile: In order to ensure that the technologies and sizes we bid into the RFP would provide optimal value to the RFP, to the LI ratepayer, and to the local community; it would be very helpful to understand the seasonal, weekly, as well as diurnal load profile, ideally by the three subareas/substations the RFP defines (section 1.2, page 2): a. Please provide the most recent 8760 hourly load profile data for these sub-areas/substations. b. If not possible, please provide peak and average load values for each sub-area during winter, spring, summer, and fall seasons. c. Please provide the Demand Response (DR) capacity currently installed in each sub-area/substation.	a. See attached excel file "2014LoadDurationCurve-ForRFPQA_Q59.xlsx" Note that this file contains actual hourly averages in MW for the year 2014 January 1 - December 31 divided per area as described in the RFP. This was the actual experianced load and not forecasted load. b. See item a c. There are approximately 941 residential thermostats and 117 non-residential thermostats enrolled in the PSEG LI Thermostat Program on the South Fork. Each residential customer location is estimated to provide 1 KW of load reduction. Further detail is unavailable at this time.
60	Grid Specific Questions In order to optimally configure aggregated resources, it would be helpful to better understand the sum of the South Fork grid dynamics: a. What are the limiting elements on the Canal to Southampton transmission system (1st & 2nd)? b. Are the South Fork needs identified exclusive of existing resources including diesels, gas turbines, and customer installed resources? c. What are the dispatch characteristics/criteria for the existing resources (e.g., when are the diesels and turbines expected to be dispatched)?	a. There are three circuits emanating east from the Canal substation. The Canal – Southampton and the Canal - Deerfield 69 kV circuit are both limited by their conductor at 112 MVA normal and LTE. The Canal to Bridgehampton cable limited by its cable conductor rating at 144 MVA normal and 184 MVA LTE. b. South Fork needs are identified under the assumption that all existing resources already in place are available and utilized/dispatched c. There are currently guidelines in place that are provided to system operators that dictate when to dispatch East End resources based on South Fork load. They are expected to be dispatched under summer peak load conditions and possibly off peak under certain maintenance conditions.
61	Renewables As LIPA from time to time requests proposals for renewable generation resources to meet its July 2013 plan to add 400 MW of new renewable resources by 2018 (e.g. August 17, 2015 RFI related to potential 4Q2015 Renewables RFP), we are interested in understanding the impact of such RFP procurements on renewables bid into the 2015 South Fork RFP. a. May renewable resources bid into this RFP also be bid into future/concurrent renewable RFPs on Long Island? b. If so, how will renewables bid into this RFP be credited for the cost avoidance of PSEG's sourcing of renewables through other RFPs?	a. Yes, however the Proposer must inform PSEG LI in the cover page that their proposal will be bid into both procurements. b. The benefits determined from the evaluation of individual proposals in one procurement do not carry over into the evaluation of other procurements.
62	Can you please provide the zip codes within the service areas identified in Figure 1-1 of the RFP?	The zip codes associated with the service areas discussed in the RFP do not directly coincide. There are times when significant overlap occures. PSEG LI recommends that each proposer refer to the USPS website to determine the proper zipcodes for each desired street location.

63	Figure 2-1 of the RFP shows that PSEGLI will need 86 MW in the Southampton load area by 2030. However, the Q&A response to Question 4 states: "With respect to Southampton, the maximum size generating unit would be approximately 10 MW based on feeder rating assuming it's a direct connection to the station." Can you please clarify this apparent inconsistency. How can we meet the 86MW load requirement in 2030 if the maximum size unit in this area is limited to 10 MW?	86 MW is needed east of Canal Substation by 2030. This can be in the form of power production or load reduction. Per Figure 1-1, there are a number of substations each of Canal. The 10 MW maximum size refers to the limit for power production resources (a subset of resources under consideration) specifically connected to the Southampton Substation, which is a subset of all the substations east of Canal.
64	Section 4.3 of the RFP states that each proposal must include a "Proposal Submittal Fee" of $1.5 per kW of load reduction or power production offered. If a proposed project has an initial capacity of for example, 10 MW, but the proposal offers PSEG the option to purchase 20 MW in the future, would the Fee be based on 10 MW or 20 MW?	The Proposal Submittal fee is based on 10 MW.
65	At this time we ask for a 1 month extension of time for submittal of RFP.	The new proposal submittal deadline is December 2, 2015 at 3PM EST.
66	Regarding MWBE Requirements: Sections 4.10 and 3.2.25 require Respondents to include their utilization plans including MWBE form 103. The instructions on MWBE form 103 state the following: INSTRUCTIONS: This form must be submitted with any bid, proposal, or proposed negotiated contract or within a reasonable time thereafter, but prior to contract award. This Utilization Plan must contain a detailed description of the supplies and/or services to be provided by each certified Minority and Women-owned Business Enterprise (M/WBE) under the contract. Attach additional sheets if necessary. Given the range of possible outcomes to the RFP and the length of time that the RFP will be open for PSEG-LI review, it is difficult for both Respondents and potential MWBE respondent subcontractors to provide the level of detail on Forms 101 and 103 prior to a PSEG-LI indication of a proposed negotiated contract award. As noted in the Form 103 instructions, please clarify if it is acceptable for a Respondent RFP submission to state that forms 101 and 103 (or in the alternative a full or partial waiver request Form 104) will be submitted within a reasonable time within notice of a proposed negotiated contract award. (We understand the processes as outlined in Form 104 page 2 would be required to be run prior to a full contract reward.)	Those Proposers that include the names and Scopes of Work for MWBE entities will receive a more favorable evaluation for the MWBE portion of the Qualitative Evaluation. However, PSEG Long Island does recognize the issue you raise and will accept the commitment of the Proposer that the MWBE goals will be met if the Proposer is selected.
67	I wanted to reach out regarding the PSEG LI SF RFP. Please let me know if you can answer the following questions: 1) For each rate class (180, 280, 281, 285), can you provide the summed value of each accounts max peak during the given year? 2) For the small commercial classes (280, 281), can you break out the SIC Group information (figure A1-2) by rate class? 3) Of the ~1,700 small commercial accounts that are cell tower packs, boat docks, and pumps, how many are in class 280? 281? 4) How many days per summer (May – September) do you project needing to call on the load reduction resources?	1) Please see Table A1-3: South Fork Electric Usage by Customer Classification. 2) This information is not available in any reliable form for the purposes of this RFP. 3) This information is not available in any reliable form for the purposes of this RFP. 4) The number of callable days for load reduction resources has not been determined. All resources are required to be available based on the information outlined in the SF RFP.

68	Is the tender of addition MW capacity to be used as a peaker? That is, will the unit be installed for capacity, and be used only for emergencies or extreme high demand? If there is an estimated number of hours that is planned to be operated, that will dictate the type of unit to be installed. SO that projection will be helpful. Is 10 minute startup time to full load required? Is there any advantage to shorter time to full load?	It is the intention of PSEG LI to use the resources sought in this RFP to offset system peaks as described in Section 1.2. However, operational requirements discussed in the Appendicies of the RFP must be met. This also applies to operational hours. The operation of these resources must adhere to the requirements of the RFP. As an example, Section 1.2.1 speaks to the requirements of Load Reduction availability. Appendix B, Section B6.1 speaks to start up times of Power Production Resources. Shorter start up times will be viewed positively.
69	a. What is the fuel source and type? b. Is there a need for dual fuel? c. Will the developer be responsible for providing the fuel to the site or will LIPA provide fuel to the site boundary? d. What is the maximum NOx limits for the operating unit? e. Is 15 PPM acceptable or will SCR be required to lower limit to 2PPM?	a. The fuel source is determined by the Developer. The decision is typically determined by permitting requirements, design and economics. b. Please refer to section 3.2.11 which covers the fuel supply plan. PSEG LI does not require liquid fuel, but does require 5 days of continous output.. c. Fuel is the responsibility of the developer. d. NOx limits are determined by the Developer's air permit which is their responsibility. e. Particulates emitted are the responsibility of the Developer based on permit requirements.
70	Is a physical location been identified for the 1st and subsequent phases? Is there any value to having the unit be mobile, able to be transported immediately to a different site? What are the typical noise limitations?	Load reduction resource locations are provided in Section A6 of the RFP. Power production resource interconnection locations are provided in Section B4.3 of the RFP. Audible noise level requirements for step-up transformers are provided in Section B13.1.2. Local codes and ordinances should be followed for other equipment.
71	Has the customer identified a Balance of Plant provider or is that the responsibility of our EPC? To better explain this, is the owner seeking a turnkey solution or will the owner provide some scope such as balance of plant equipment? Where will the responsibility end for the project scope? High side of transformer, at the substation?	You and your EPC are responsible for identifying a BOP provider. The Owner will not be providing any scope. Power production resource interconnection locations are provided in Section B4.3 of the RFP, and NYISO and LIPA interconnection rules are provided in Section B2.1 of the RFP.
72	Is this RFP to drive a separate request for increased T&D capacity for the network? Is funding in place for the RFP?	The purpose of this RFP is proposed as "an alternative to adding new transmission lines, this Request For Proposals (“2015 SF RFP”) seeks to acquire sufficient local resources to meet expected peak load requirements until at least 2022 in the South Fork, and 2030 in the east of Buell subarea."
73	Is there any advantage to have multiple units that add up to the total megawatt need or will one unit be acceptable?	Capacity requirements for power production resources are provided in Section B7.1 of the RFP. Additionally, Table 5-2 provides a qualitative evaluation criterion for sizing flexibility, which indicates that there is value to having multiple unit flexibility.

74	What order of value will be considered for selection: a. $/kW b. Efficiency c. Flexibility d. Startup time e. Fuel flexibility f. Mobility g. Footprint size	Quantitative evaluation criteria are provided in Section 5.4.1 of the RFP, and qualitative evaluation criteria are provided in Section 5.4.2. There is no order of value.
75	Is there any value to having the power production earlier that specified? If yes, how many MW are valued earlier?	See answer to Question 16.
76	Is land provided by LIPA, if so, what is the lease rate?	At the present time LIPA will not offer any of the land it owns for the purpose of this procurement.
77	If land is not provided by LIPA, is evidence of land control required by LIPA for bid compliance?	See Section B4.2 of the RFP for site control requirements.
78	How much land is available at each possible site?	See answer to Question 76.
79	Is available land zoned and what permits are required?	See answer to Question 76.
80	Will LIPA purchase more electricity than the 8MW in the first phase, Can we build complete system up-front?	Yes. Based on the details of the Proposal PSEG LI will consider procuring more than 8 MWs in 2017 and 2018.
81	What is the specific date LIPA needs production of the first 8MW in 2017? Can this date be extended?	Per Section 2.1 of the RFP, the preferred COD for 2017 resources is May 1, 2017.
82	Regarding the submittal of the RFP response, the deadline listed in the RFP is November 13, 2015 no later than 3:00 p.m. ET. Please clarify if time stamp applies to the proposal package being sent out for delivery, or to the time of the receipt of the package by your team.	The receipt of the package must occur by the deadline, which is now December 2nd at 3PM EST.
83	South Fork Historical Experience with Demand Response. The response to question number 59 part c is helpful description of the current participation in the demand response program. a. How often has the demand response program called upon customer thermostats in each of the past five years? What has been the magnitude of DR capacity (in kW) that were called in each of the events? b. When called, is demand reduction requested of all participants?	a. The total number of events initiated over the last five years was 5. This includes 2 days in 2015, 1 day in 2014, 2 days in 2013, 1day in 2012, and 0 days in 2011. All customer thermostats participating in the program are called and activated. The number of participants in the program has been fairly consistent, and the program capacity is approximately 30 MW. b. During an initiated event, all active two-way communicating programmable thermostats in the program are called and demand reduction is requested.
84	Distribution system detailed information. Distribution connected DER solutions for various potential points of interconnection are under evaluation. To properly engineer and compare these potential solutions it is important to have the information requested below for the Southampton, Deerfield, Bridgehampton, East Hampton, East Hampton GT, Buell, Hither Hills and Montauk substations: a. Single line diagrams (showing distribution buses and feeders), general arrangements, site plans, protection and metering diagrams and communication architecture diagrams. b. Please provide 13kV feeder distribution diagrams (GIS or geographical diagram preferred). c. Is there available land on these LIPA substation sites (or other LIPA sites in the South Fork area) that would be available to lease? Please identify where.	a) A CRITICAL ENERGY INFRASTRUCTURE INFORMATION (“CEII”) NON-DISCLOSURE AGREEMENT is now posted on the website. Please submit it to the RFP email address. b) A CRITICAL ENERGY INFRASTRUCTURE INFORMATION (“CEII”) NON-DISCLOSURE AGREEMENT is now posted on the website. Please submit it to the RFP email address. c) See answer to Question 76.

85	Clarifications In reviewing the RFP and Q&A log we have questions in these two areas: a. Section 4.3 identifies the required application fee to be calculated based on the "…kW of load reduction and power production resources offered." When submitting a variety of resources in a single response with different capacity factors, is this calculation based on the firm kW of resources offered or the aggregated nameplate capacity? For example, if three assets are submitted together as a firm 1MW offer based on each asset having 1MW of AC capacity and 33% capacity factor (estimated) – would the proposal fee be based on the 1MW of load reduction/power production being offered or the 3MW of nameplate asset capacity included in the response? b. When will draft PPA's be available? The answer to Question 31 has offered September 8th and then 30th as target dates previously. Perhaps it has been posted and we have missed it.	a. The fee would be based on the 1MW of load reduction/power production being offered. b. This procurement is unusual in that the choices of technologies is not restricted as in the past. In order to accommodate this, contracts needed to be developed to accommodate this expanse of technologies that are fair and do not favor one technology over the other. PSEG LI is hopeful that all associated contracts will be posted on the website by October 30th.
86	I wanted to inquire into the timing of your making draft contracts available on the RFP website. We are engaging our external counsel to review and adapt those contracts for our RFP response and we would really appreciate being able to review your initial drafts before taking it into any specific direction	This procurement is unusual in that the choices of technologies is not restricted as in the past. In order to accommodate this, contracts needed to be developed to accommodate this expanse of technologies that are fair and do not favor one technology over the other. PSEG LI is hopeful that all associated contracts will be posted on the website by October 30th.
87	For equipment installation in this area, will you please confirm union work or prevailing wage requirement? And if union is required, will you confirm Union (IBEW?) & Local union?	Union labor is not required. The selection of union or non union labor is a decision to be made by the Developer based on purely business practices and their experiences in project development. Prevailing wages are required. Prevailing wage rates will be posted on the RFP website shortly.
88	The RFP indicates that Respondents may choose to emulate or enhance the PSEG efficiency and renewable programs. Can respondents also participate in NYISO demand response programs?	No. The load reduction products/services solicited under the RFP are intended to solicit participation in a retail load reduction program administered by PSEG Long Island on behalf of LIPA and, as such, they will not be bid into the NYISO wholesale market. Respondents cannot sell/bid the load reduction programs/services that are accepted as a result of this RFP into the NYISO wholesale market. Respondents are responsible for contracting with LIPA's retail customers with respect to any load reduction program/service submitted as a proposal in response to the RFP.

89	Could you please clarify to what extent the load profiles in the "2014 Load Duration Curve" document match up with specific substations and the geographic boundaries described in the RFP? When we added the three profiles in the load duration curve document, there was a peak demand of 207.8 MW for 2015, but the RFP forecasts a peak demand of 286 MW for 2015 (page 49). Can you explain why the peak demand for 2015 is so much higher than the peak for the sum of the profiles in the 2014 data?	The data supplied was actual load experienced for summer 2014 and correctly correlates to the substation boundaries as specified in the RFP. The peak forecast for 2014 was 279 MW (slightly lower than the 2015 286 MW forecast). The load conditions experienced in 2014 were not indicative of the peak forecast due to a milder than expected summer. Additionally, one of the biggest distinctions to consider is that the South Fork demand forecast (page 49 in RFP) includes load at the Canal substation. However, as part of this RFP we are not seeking to obtain resources at Canal, but rather East of Canal, so Canal load is not included in any of the RFP boundary totals. For reference the Canal load amounted to 22 MW when correlated with the referenced 207.8 MW peak making the total South Fork experienced peak in 2014 to be 230 MW.
90	We understand that standard contract terms may be provided for three categories of resources: dispatchable, non-dispatchable, and demand response. Could you please clarify which category would apply to (1) energy efficiency and (2) permanent load shifting (i.e. controlling loads to shift demand out of system peak hours by default)?	Energy Efficiency programs and permanent load shifting assets behind the customer meter will be provided under a non-dispatchable Energy Services agreement.
91	Is it correct to assume that ADR will be the preferred protocol to interface with all types of resources (whether it is energy storage or controllable load devices)? Typically, when sending setpoints to third parties, the utility sets up a platform with only 'outgoing' traffic. Under this arrangement, there is no requirement to receive 'input' from the outside into the utility and therefore it does not touch the 'secure network' (UDN) of the utility. Is it correct to assume that resources will not have a requirement to interface with the utility's secure network?	The resources may have a bi-directional interface with the feedback traffic entering the PSEG LI secure corporate network. The DRMS system needs to support interoperability across multiple energy management products and devices by means of the industry standard data exchange protocols such as Zigbee SEP, HAN Zigbee or Homeplug, and OpenADR and to integrate in the quasi-realtime enterprise service bus environment using industry standard web services protocols (SOAP or REST over either XML or JSON)
92	If historical pricing information is not available, will it be acceptable to make a proposal with just a capacity price per kw/month and no pricing for energy per kWh and just make the cost and benefit of charging and discharging a pass through to PSEG?	For energy storage bids, it is possible to have only a capacity price. The bidder only needs to provide the technical performance relating to charging/discharging (e.g., cycle efficiency, hours, MW, etc.). The bidder does not have to provide the value of that pass-through cost to LIPA.

93	With regards to Question 67 – "For each rate class…during the given year?" – can you provide the summed value of the customer-specific peak load for each Rate Class, regardless of the time of year. Not all customers will have their location-specific peak load during the aggregate peak load (which was provided in Table A1-3).. This would be helpful in sizing the load control opportunity. I have included an example below. Example: Cust 1 => 100 kW on 3/1/14 was site specific peak for the year; 50kW on 6/15/14 Cust 2 => 150 kW on 6/15/14 was site specific peak of the year Cust 3 => 200 kW on 6/15/14 was site specific peak of the year Aggregate Peak Event was on 6/15/14 and yielded a peak of 400kW Sum of each customer's max peak was 450kW For Load Reduction Resources, are solutions desired through 2030? For Load Reduction Resources, is customer load data available by Boundary (A, B, and C)? To ensure that RFP responses are submitted in a thorough and complete manner, for each section, can you identify the type of solutions that are required to respond?	Table A1-3 should be used to determine the peak load of each rate class. For load reduction resources, solutions may be provided in increments of 5 year, 10 year, 15 year, and 20 year timeframes. Customer data is not available by the boundaries outlined in the RFP. The type of solutions provided are strictly determined by the bidder to this RFP.
94	Page 3 says "Additional value will be attributed to such proposals in the evaluation process with respect to increased avoided costs and /or reduced administrative costs." Can you share how these costs are going to be evaluated?	See answers to Questions 53 and 74.
95	Page 3 also states "....accept proposals that only partially meet these requirements if proposals are not able to meet full requirements". Will preference be given to proposals that meet all of the requirements? How will they be weighed against each other?	See answers to Questions 53 and 74.
96	Will the DLC equipment mentioned on page 53 still be replaced in 2016?	The load control devices now associated with the LIPA Edge program will not be replaced in 2016, but there is an expectation that the devices will be replaced in the next several years as funding permits.
97	On page 53 "All databases...shall become the property of LIPA." Can you clarify?	LIPA will have ownership of all customer related information, program detail, and technical information related to this RFP
98	Page 55 "Respondent shall be responsible for providing PSEG LI with remote access to its entire program related sales and operations tracking and reporting databases." Please clarify what you mean by remote access.	PSEG Long Island will require electronic access to any and all databases that contain customer records and detail customer performance as related to any load reduction program covered under this RFP
99	Page 55 "Respondent should provide a full marketing plan and timeline, including optional contingency mechanisms and levers to boost enrollment as needed." Is this required at the proposal phase or upon being awarded the contract?	The response to the RFP should detail the marketing plan, including target markets and efforts required to secure the amount of customers required (market segments, outreach, advertising, etc) and load reduction MWs a respondent submits within the bid for this RFP.

100	Page 56 - What are the specific penalty rates mentioned?	Penalty rate details for non performance are outlined in the Energy Services Agreement that will be included with this RFP, and posted on the PSEG Long Island website.
101	Are design studies required for load reduction resources?	Design studies are requested if interconnecting to the T&D System. Per Section B17, design studies are requested to ensure Power Production resources are compatible with the T&D System. Specific requirements and specifications applicable to Power Production resources are contained in Appendix B. Specific requirements and specifications applicable to Load Reduction resources are contained in Appendix A. However, since batteries/energy storage are acceptable responses to this RFP, energy storage may be proposed as a peak shaving device under the load reduction application (Appendix A). For energy storage as a power producing source, it does need to comply with these technical requirements to support the PSEG Long Island system and criteria (Appendix B).
102	p 56 "load reduction tests may be conducted prior to the season" - Will PSEG take into account that for weather sensitive load, results may be lower than expected due to being prior to the season?	Load reduction information will be weather and seasonally adjusted.
103	For weather sensitive loads (thermostats/HVAC) will PSEG consider approximations for varying levels of kW/month through the season?	All MW included within a load reduction bid must be delivered as per the timeframes detailed in the RFP
104	Can we propose a cost structure that includes monthly operations or a management fee along with a cost per KW delivered?	Yes. The evaluation of each proposal will, in part, include all costs required by the Respondent.
105	Regarding Resource Requirements outlined on page 7 section 1.2.3 of the RFP: a. if no curtailment event is called, is the reservation fee paid to winning bidders unadjusted from proposed values each month? b. is the payment of the reservation fee guaranteed throughout the duration of the contract term? (e.g., one payment each month May – September for a term of 5 years = 25 contracted payments for the proposed resource) c. On page 7 reference is made to "The first payment…" at end of first month after installation of resource, are other alternative proposed payment schedules acceptable such as progress payments? d. please clarify if this "first month" is only those months identified on page 5 section 1.2.1.c (May-Sept) or the first month that the resource is available	The Energy Services Agreement is posted on the PSEG LI website. The PSEG LI procedures and preferences for payments related to Demand Reduction is contained within. Any suggested modifications to this can be posed via redline changes to this document.
106	If a resource is not guaranteed to be fully available "under any meteorological conditions existing during program operational hours" as specified in section 3.2.9, page 20 of the RFP, does that classify a proposal which includes such resources as "non-responsive"?	Load reduction resources must be available during the program timeframes, season, and load reduction operational hours.

107	It appears that many of the proposal requirements in Section 3.2 are geared towards Power Production proposals only. Please clarify if these sections, specifically 3.2.4; all or part of 3.2.5; 3.2.9; 3.2.10; 3.2.11; and all of 3.2.12 including subsections 1-7, and sections 3.2.13 through 3.2.19 are relevant and required for Load Reduction resources. Note that there is a comment identified with the initials "NB" alluding to such, however, not all subsections here have that same NB comment.	The sections you refer to are not for Load Reduction resources. The NB (Nota Bene) comments are to assist the Respondents in understanding the applicability of various requirements.
108	Please clarify that the referenced "Form of Agreement or Contract" in section 3.2.24 on page 35 of the RFP is the document titled "CONFIDENTIALITY AND NON-DISCLOSURE AGREEMENT" a word doc file named "LIPAServcoNDA.docx" on the RFP website. This may be confused with a document on the website referred to as the "Standard Consulting Agreement" which is titled "APPENDIX B- PARTICIPATION BY MINORITY GROUP MEMBERS AND WOMEN WITH RESPECT TO STATE CONTRACTS: REQUIREMENTS AND PROCEDURES"	Section 3.2.24 refers to the Power Purchase Agreements (Power Production and Non-Dispatchable) which will be utilized for all resources with the exception of Demand Response and also the Services Agreement that pertains to Demand Response and Energy Efficiency.
109	PSEG-LI's response to Question 86 on the Question and Answer Log indicated that all draft contracts would be posted to the RFP website by October 30th. Respondents will need sufficient time to review these contracts and develop a redline version per the RFP requirements. When will these contracts be made available?	The PPAs for Dispatchable and Non-dispatchable Resources are posted. The Service Agreement for Demand Response will be posted no later than November 9th.
110	The RFP mentions that respondents for Load Reduction resources should include optional contingency mechanisms to boost enrollment as needed. For respondents that propose an aggregation of a portfolio of DERs, would adjusting the technology mix and/or set of customers in the portfolio be acceptable contingency mechanisms?	Yes.
111	Can you please provide additional information about the estimated average and maximum number of days per year that callable load reduction resources would be called to reduce load?	Callable resources are required to be available as outlined in the RFP. All callable resource needs will be intiated based on the electric system needs and performance
112	Is PSEG LI willing to re-assess its requirement for the listed Proposal Fee? In our extensive practice responding to RFPs, the preferred arrangement that we have observed is for parties to submit a refundable proposal fee, which is given in the form of a bid bond or certified bid security check. All parties responding will pay the fee amount upon submitting the proposal response. However, once the award is made to the bid winner, all other parties are refunded the proposal fee. Is PSEG willing to have this arrangement? Alternatively, can you clarify the rationale for the significant amount requested? Based on our past experience, this amount appears to be significantly higher than any other required proposal fee expected for other projects.	The proposal fee is firm for the purposes of this procurement.
113	On page 55 of the RFP it says, "Respondent shall be responsible for providing PSEG Long Island with remote access to its entire Program related sales and operations tracking and reporting databases." Can you please clarify and specify which information PSEG Long Island requires?	PSEG Long Island will require electronic access to any and all databases that contain customer records and detail customer performance as related to any load reduction program covered under this RFP

114	Page 57 of the RFP states that inverters shall have "voltage ride-through capabilities compliant with California Public Utilities Commission Electric Tariff Rule 21, Section H.1.a.(2) and Table H.1." Section H.1.a.(2) and Table H.1 do not include voltage ride-through requirements**, but rather only include requirements for voltage and frequency trip. Can you please clarify if the only requirement is for tripping as specified in Section H.1.a.(2) and Table H.1, or if there is an additional requirement for voltage ride-through? If there is an additional voltage ride-through requirement, can you please provide additional details about this requirement? **Here is an example of a draft voltage ride-through table, from the CA Rule 21 smart inverter working group from 2014. Note that it includes "stay connected until" requirements, which differentiate ride-through requirements from trip requirements. http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/Recommendations_for_updating_Technical_Requirements_for_Inverters_in_DER_2014-02-07-CPUC.pdf See Table 1 on page 26.	The references in the California Public Utilities Commission Electric Tariff Rule 21 were incorrectly stated in the RFP (which will be amended shortly) The correct references are: **Section Hh.2.b(ii)** **Table Hh.1** **Section Hh.2.f(i)** **Table Hh.2**
115	Do you have any data on how many of the 40k residences are occupied by their owners vs. rented out during the peak months?	PSEG LI does not have this data. Often rental utility bills are kept in the name of the property owner which would give PSEG LI the false impression that the residence is not a rental.