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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources.	Rulemaking 14-10-003 (Filed October 2, 2014)

AMENDED SCOPING MEMO AND RULING OF ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE

Summary

Pursuant to Public Utilities Code § 1701.1 and Article 7 of the Commission's Rules of Practice and Procedure,[1] this amended Scoping Memo and Ruling: 1) changes the category of this proceeding from quasi-legislative to rate setting; 2) for procedural efficiency, combines the remainder of the phase one issues with the second phase issue of setting an incentive level for the proposed regulatory incentive mechanism pilot; and 3) provides parties an opportunity to comment on and respond to questions regarding the attached revised proposal for a regulatory incentive mechanism pilot, which includes a proposed incentive level.

1. Background

On October 2, 2014, the Commission established Rulemaking (R.) 14-10-003 to consider the development and adoption of a regulatory framework to provide policy consistency for the direction and review of

[1] California Code of Regulations, Title 20, Division 1, Chapter 1; hereinafter, Rule or Rules.

demand-side resource programs. On December 5, 2014, a prehearing conference was held to determine parties, discuss the scope, the schedule, and other procedural matters. Subsequent to the prehearing conference, the assigned Commissioner and Administrative Law Judge issued a Ruling and Scoping Memo indicating that the rulemaking would be undertaken in two phases, with the first phase focused on a review of various integrated demand-side management issues. The second phase of the proceeding would be focused on the development of required mechanisms based on the outcomes of phase one, possibly including shareholder incentive mechanisms.[2]

An amended scoping memo was issued on February 26, 2016 as a result of Decision (D.) 15-09-022, which authorized an expanded scope for the proceeding. The amended scope now focused on four issues in phase one: 1) development of a competitive solicitation framework; 2) the continued development of technology-neutral cost-effectiveness methods and protocols; 3) leveraging of the work performed in Rulemaking 14-08-013 (*i.e.,* the Distribution Resource Plans Demonstration Projects); and 4) the Utility role, business models, and financial interests with respect to distributed energy resources deployment.

In an April 4, 2016 ruling, the assigned Commissioner proposed a draft regulatory incentive pilot and provided parties an opportunity to comment on and respond to questions regarding the pilot. Parties filed comments on May 9, 2016 and reply comments on May 23, 2016. The Commission held public workshops on June 13, 2016 and August 4, 2016 to discuss the proposed pilot.

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[2] Joint Assigned Commissioner's and Administrative Law Judge's Ruling and Scoping Memo, January 5, 2015.

2. Categorization

In the Order Instituting Rulemaking, issued on October 2, 2014, the Commission preliminarily determined that the category of the proceeding is quasi-legislative for the first phase and ratesetting for phase two. The January 5, 2015 Scoping Memo confirmed that categorization.

For efficient determination of the issues in this case, this amended scoping memo combines the remaining issues into one phase and revises the categorization from quasi-legislative to ratesetting. The change in categorization is due to the fact that a ratesetting element will be considered; *i.e*. an incentive level for the proposed regulatory incentive pilot. As indicated in the original scoping memo, ratesetting elements such as incentives should be addressed in a ratesetting proceeding.[3] Anyone who disagrees with this categorization must file an appeal of the categorization no later than ten days after the date of this scoping ruling. (*See* Rule 7.6.)

3. Scope

For efficient determination of the issues in this proceeding, the remaining issues from the two phases of this proceeding are hereby combined into one phase such that the following issues are within the scope of this proceeding:

1. Development of a competitive solicitation framework targeting the reliability needs within the areas identified by the Integration Capacity Analysis and the Locational Net Benefits Analysis performed in Rulemaking 14-08-013. The framework will address the following elements:
   a. Defining the services to be bought and sold within the identified areas;

[3] Joint Assigned Commissioner's and Administrative Law Judge's Ruling and Scoping Memo, January 5, 2015 at 2-3.

   b. Development of methodologies to count services provided, ensuring no duplication or double-counting of resources;
   c. Development of solicitation rules or principles;
   d. Development of solicitation oversight needs;
   e. Development of solicitation evaluation methodology; and
   f. Development of solicitation pro forma contract.

2. Continued development of technology-neutral cost-effectiveness methods and protocols, including but not limited to:
   a. Refinement and enhancement of valuation or cost-effectiveness methods; and
   b. Informing or determining a preferred approach to bid evaluation within the competitive solicitation framework.
3. Leveraging the work being performed through the Distribution Resource Plans Demonstration Projects where practical, for the purpose of advancing the development of a competitive solicitation framework for distributed energy resources.
4. Utility role, business models, and financial interests with respect to distributed energy resources deployment. This proceeding will consider whether to pilot a proposal for financial shareholder incentives. Furthermore, this proceeding will also consider establishing the incentive level.

4. Need for Hearing

The Commission in the Order Instituting Rulemaking also preliminarily determined that hearings are not required. We confirm that determination here.

5. *Ex Parte* Communications

In a ratesetting proceeding such as this one, *ex parte* communications with the assigned Commissioner, other Commissioners, their advisors and the Administrative Law Judge are only permitted as described at Public Utilities Code § 1701.3(c) and Article 8 of the Rules.

6. Intervenor Compensation

Pursuant to Public Utilities Code § 1804(a)(1), a customer who intends to seek an award of compensation must file and serve a notice of intent to claim compensation by 30 days after the prehearing conference; we do not intend to hold another prehearing conference. However, because the two phases of the proceeding have been combined into the current phase, we allow new parties to file and serve notice of intent to claim intervenor compensation within ten days of the issuance of this amended Scoping Memo.

7. Assigned Commissioner

Michel Peter Florio is the assigned Commissioner and Kelly A. Hymes is the assigned Administrative Law Judge.

8. Filing, Service and Service List

The official service list has been created and is on the Commission's website. Parties should confirm that their information on the service list is correct, and serve notice of any errors on the Commission's Process office, the service list, and the Administrative Law Judge. Persons may become a party pursuant to Rule 1.4.

When serving any document, each party must ensure that it is using the current official service list on the Commission's website.

This proceeding will follow the electronic service protocols set forth in Rule 1.10. All parties to this proceeding shall serve documents and pleadings using electronic mail, whenever possible, transmitted no later than 5:00 p.m., on the date scheduled for service to occur. Parties are reminded, when serving copies of documents, the document format must be consistent with the requirements set forth in Rules 1.5 and 1.6. Additionally, Rule 1.10 requires service on the Administrative Law Judge of both an electronic and a paper copy of filed or served documents.

Rules 1.9 and 1.10 govern service of documents only and do not change the Rules regarding the tendering of documents for filing. Parties can find information about electronic filing of documents at the Commission's Docket Office at www.cpuc.ca.gov/PUC/efiling. All documents formally filed with the Commission's Docket Office must include the caption approved by the Docket Office and this caption must be accurate.

Persons who are not parties but wish to receive electronic service of documents filed in the proceeding may contact the Process Office at process_office@cpuc.ca.gov to request addition to the "Information Only" category of the official service list pursuant to Rule 1.9(f). Discovery

Discovery may be conducted by the parties consistent with Article 10 of the Commission's Rules. Any party issuing or responding to a discovery request shall serve a copy of the request or response simultaneously on all parties. Electronic service under Rule 1.10 is sufficient, except Rule 1.10(e) does not apply to the service of discovery and discovery shall not be served on the Administrative Law Judge. Deadlines for responses may be determined by the parties. Motions to compel or limit discovery shall comply with Rule 11.3.

9. Public Advisor

Any person interested in participating in this proceeding who is unfamiliar with the Commission's procedures or who has questions about the electronic filing procedures is encouraged to obtain more information at http://consumers.cpuc.ca.gov/pao or contact the commission's Public Advisor at 866-849-8390 or 415-703-2074 or 866-836-7825 (TTY), or send an e-mail to public.advisor@cpuc.ca.gov.

10. Revised Regulatory Incentive Mechanism Pilot Proposal

Attached is a revised proposal for the regulatory incentive mechanism pilot. Parties are asked to review the revised proposal and respond to the questions below. To the extent party positions are the same as submitted in earlier comments, parties should simply acknowledge as much. There is no need to repeat comments already made.

1) Would the attached pilot proposal accomplish its stated purpose, to test how an earnings opportunity affects the utilities' distributed energy resources sourcing behavior?
2) Would an incentive program such as that described in the attached proposal achieve the objective of promoting the cost-effective deployment of distributed energy resources? If not, why not?
3) Does the attached proposal appropriately balance the need to execute the pilot on a reasonable schedule and provide adequate oversight of implied cost to ratepayers?
4) Does the pilot proposal effectively complement and leverage recommendations made by the Competitive Solicitation Framework Working Group's August 1, 2016 Report and the Distribution Resource Plan Demonstration C in Rulemaking 14-08-013?
5) Are there changes to the attached proposal that you see as essential and without which you would not support adoption of the proposal?

11. Schedule

The adopted schedule is as follows:

EVENT	DATE
Comments Filed on Attached Revised Pilot Proposal	14 Days from the issuance of this amended Scoping Memo
Reply Comments Filed on Attached Revised Pilot Proposal	21 Days from the issuance of this amended Scoping Memo

The assigned Commissioner or assigned Administrative Law Judge may modify this schedule as necessary to promote the efficient management and fair resolution of this proceeding.

It is the Commission's intent to complete this proceeding within 18 months of the date this Scoping Memo is filed. This deadline may be extended by order of the Commission (Public Utilities Code § 1701.5(a).)

If there are any additional workshops in this proceeding, notice of such workshops will be posted on the Commission's Daily Calendar to inform the public that a decision-maker or an advisor may be present at those meetings or workshops. Parties shall check the Daily Calendar regularly for such notices.

IT IS RULED:

1. The category of this proceeding is ratesetting. Appeals as to category, if any, must be filed and served within ten days from the date of this amended scoping memo.
2. The scope of the issues for this proceeding is as stated in "Section 3. Scope" of this ruling.
3. An Evidentiary Hearing is not necessary.

4. With limited exceptions that are subject to reporting requirements, *ex parte* communications are prohibited. *See* Public Utilities Code § 1701.3(c); Article 8 of the Commission's Rules of Practice and Procedure.)

5. New intervenors may file and serve notice of intent to claim intervenor compensation within ten days of the issuance of this amended Scoping Memo.

6. The schedule for the proceeding is set in "Section 10. Schedule" of this ruling. The assigned Commissioner or Administrative Law Judge may adjust this schedule as necessary for efficient management and fair resolution of this proceeding.

Dated September 1, 2016, at San Francisco, California.

/s/ MICHEL PETER FLORIO	/s/ KELLY A. HYMES
Michel Peter Florio	Kelly A. Hymes
Assigned Commissioner	Administrative Law Judge

ATTACHMENT

REVISED ASSIGNED COMMISSIONER PROPOSAL FOR DISTRIBUTED ENERGY RESOURCE INCENTIVES

REVISED ASSIGNED COMMISSIONER PROPOSAL FOR DISTRIBUTED ENERGY RESOURCE INCENTIVES

On April 4, 2016, I issued a ruling in this proceeding introducing a draft proposal for a pilot program to award regulatory incentives to the three large investor-owned electric utilities in California (the IOUs) for the cost-effective deployment of Distributed Energy Resources (DERs) that defer or displace more traditional distribution capital projects and expenditures. Two public workshops have been held on the draft proposal and several rounds of thoughtful comments have been submitted. Based on all of this very constructive discussion, I am now revising the proposal as set forth below.

A. Why Consider Utility Incentives to Deploy DERs Now?

Some parties, including most prominently the IOUs themselves, question the wisdom and necessity of instituting an incentives pilot at this time. I have considered those comments carefully, but continue to believe that the time is right to begin to examine the issues raised by DERs in the context of the existing regulatory framework and utility business model in California. While much work remains to be done -- both in this proceeding and in the related Distribution Resource Planning (DRP) docket -- on a wide variety of topics, I believe that tackling these financial issues now will send the right signal to all interested observers that California is serious about this endeavor and expects to see results sooner rather than later.

The IOUs express concern that controversy around the awarding of incentives might delay or distract from other important work, both in this case and in the DRP. This is an important caution; but I believe that we can structure a modestly-sized pilot that will consider the effect of incentives without excessive controversy or distraction. At minimum, our willingness to address this issue upfront should signal the investment community that our efforts to transform the California electric system will not be undertaken without regard for the continued financial health of the IOUs, even if the regulatory and ratemaking framework that ultimately evolves in California turns out to be quite different from the one currently in place. Throughout the important and dramatic changes currently sweeping this industry, our focus must remain on assuring safe, reliable and environmentally-sensitive electric service at just and reasonable rates, while maintaining financially healthy infrastructure providers.

My initial draft incentives proposal relied heavily on two papers that discussed the concept of "r-minus-k" as the "value engine" for utility investors. These ideas attracted considerable commentary, with the utilities in particular strongly contesting the validity of the concept and its applicability to current utility operations in California. Rather than delving more deeply into that debate, or attempting to base an incentive on a particular measure of "r-minus-k," I am revising the initial proposal to suggest a more familiar approach to the determination of incentives, similar to our current Efficiency Savings and Performance Incentive (ESPI) for energy efficiency. This shift does not imply a rejection of the "r-minus-k" concept, but rather recognition that a less controversial basis for the pilot is desirable at this time.

The New York Public Service Commission has already identified some of the shortcomings of the traditional ratemaking model in its May 19, 2016 "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework":

> Staff accurately described how cost-of-service ratemaking contains implicit disincentives to innovate in developing improvements that meet consumer needs at a reduced level of expenditures. This is one of the principal shortcomings of the traditional method, and its implications for a utility transition to a platform role are clear.
>
> The question of whether there is a bias toward capital spending is less important than the concern that utilities have a more general incentive to favor their own spending over third-party investment. Even if the difference between capital and operating expenditures were eliminated, utilities will still have incentives, both financial and institutional, to favor their own spending and their

> own facility investments. The current framework encourages a natural tendency in utilities toward investments that utilities make and control, versus an inclination to favor the use of third-party resources where they offer economic, reliability and environmental benefits to consumers and the grid. (NY PSC Order, May 19, 2016 at 32-33)
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> In order for utilities to enable these developments, they must take actions that run counter to the practices that are encouraged by traditional ratemaking. At the planning and operational level, this means enabling markets for distributed resources that will complement, and eventually transform, the centralized unidirectional system. At the revenue and earnings level, this means actively pursuing results that could be adverse to the interests of a utility under classical ratemaking. These results include lower sales volume, reduced capital expenditures, and greater reliance on market-driven outcomes as opposed to cost-of-service inputs. (*Id*. at 35)
>
> In sum, along with the other complementary changes we are requiring in utility planning and information sharing, the pricing of distributed resources, and retail market reform, the ratemaking reforms are designed to ensure that rather than resisting third party investments and operational and market changes that increase consumer value and the achievement of critical State economic and environmental goals, New York utilities will embrace these changes as consistent with and vital to their own financial interests. (*Id*. at 40)

The comments in this proceeding identify a number of other utility disincentives to the deployment of DERs that go well beyond the "r-minus-k" concept. The IOUs themselves identify a number of these – "DER sourcing and contract administration may require additional utility staff and resources. Similarly, DER integration to the grid is expected to create some additional costs, e.g. DER control systems." (May 9 Joint IOU Comments at 9). Also, "the dearth of available real-world data and information regarding the practical deployment of DER on utility systems; a lack of clarity in expected changes to the utilities' distribution planning processes and the oversight included as part of those changes; uncertainty in the commercial ability of the market to provide operational and cost-effective DERs; guaranteeing performance of DERs so they provide necessary grid services; and the difficulty in differentiating the DERs deployed through utility sourcing (*i.e.*, incremental resources) from the DERs built into planning forecasts (*i.e.*, already assumed resources)," as well as the familiar "debt equivalence" concerns. (*Id*. at 12).

Likewise, other parties spoke to a number of additional barriers to the use of DERs well beyond the financial – the ease and familiarity of traditional approaches, the perceived risks of DERs, institutional barriers, cultural inertia and conservatism, historical expertise, the need for new staff competencies and internal processes, engineering and operational uncertainties, lack of control, and general anxiety toward change. While many of these are entirely understandable, they do constitute real barriers to the deployment of DERs to provide essential distribution reliability services.

Indeed, as pointed out by one of the IOUs at an earlier workshop, this is not the first time that this Commission has directed the utilities to consider the use of at least one form of DER – distributed generation -- in their distribution planning processes. In 2003, D.03-02-068 directed the IOUs as follows:

> Within 75 days of the effective date of this decision, PG&E, SDG&E and SCE shall file a compliance filing describing the methodology each will use for evaluating distributed generation as a distribution alternative. The methodology shall be specific enough to provide the distributed generation community with information on when distributed generation may be an alternative for a distribution system modification or upgrade, while giving the utility flexibility to react to changes in the distributed generation marketplace. (Ordering Paragraph #2, p. 81)

Today, over 13 years later, there are very few examples of this process having successfully resulted in the deployment of distributed generation to displace a distribution system upgrade. This history strongly suggests that the offering of an incentive certainly cannot hurt in stimulating greater opportunities for DERs.

The utilities have argued that an explicit financial incentive is not necessary at this time to satisfy their investors. If this is true, then the funds received in the form of an incentive need not be distributed as earnings – they could be used by the IOUs to provide spot bonuses or other monetary incentives to their employees in distribution planning and related areas who are being asked to modify their traditional approach to their work. Indeed, given the many institutional and cultural barriers discussed above, this might prove to be even more effective than offering additional compensation to shareholders.

B. The Need for and Structure of the Incentive

One might ask: why provide the IOUs with any incentive at all? Why not just *direct* the utilities to choose DERs whenever they are less costly than traditional distribution investments? One answer is that the Commission already did that, in D.03-02-068, with very limited results. Further, given the complexity of the distribution system, and the developmental stage of the Locational Net Benefits Analysis (LNBA) and Integration Capacity Analysis (ICA) methodologies being vetted in the DRP proceeding, this Commission is presently not yet equipped to determine with the necessary specificity exactly when and where such DER deployment opportunities may exist. Instead, if our objectives are to be achieved, we should create appropriate utility incentives, such that the IOUs will affirmatively seek opportunities to deploy DERs in the pursuit of their own economic interests.

The offering of shareholder incentives for utility deployment of cost-effective DERs should not come at the expense of ratepayers – as long as the amount paid to the

DER provider[4], plus the cost of the utility incentive, is less than the cost of the avoided or deferred utility capital investment, ratepayers should always be better off paying the incentive than if the utility had just gone ahead with the planned investment. The development of the LNBA, currently within the scope of the DRP, is central to this effort, limiting the active deployment of DER to locations where the benefits exceed the cost. I propose to establish such a limitation for purposes of this pilot, in order to ensure that ratepayers are not disadvantaged in the process of encouraging increased deployment of DERs.

Regulatory incentives in such situations have often taken the form of "split-the-savings" structures, in which both ratepayers and shareholders receive a portion of the savings achieved by the selection of a lower cost option. While some parties advocate the use of such an approach for DER incentives in the future, none have argued that we are ready to adopt such a methodology now. I do not wish to create a pilot structure that will promote extensive litigation over the amount of the incentives to be awarded. Indeed, uncertainty over the amount of any eventual award may act as a contrary incentive, potentially leading the utility to choose the relative certainty of earning a return on a traditional capital investment, rather than take on the risk that a regulatory incentive might (or might not) eventually be awarded.

For this reason I propose to offer a shareholder incentive for the deployment of cost-effective DERs that displace or defer a utility expenditure, based on a fixed percentage calculation. My initial proposal suggested applying this percentage to the

[4] The DER provider could be either an aggregator of DER services, and individual vendor, or perhaps even a single large customer.

annual payments made to the DER provider (customer or vendor).[5] This approach is simple, straightforward, and not particularly prone to dispute (at least as to the amount of the incentive). As pointed out by a number of commenters, however, if the DER solution is markedly cheaper than the displaced traditional distribution alternative, the utility might still be better off financially if it chose the rate-based investment (the "investment scale" problem).

Vote Solar, in particular, recommends that the incentive percentage be applied to the dollar amount the IOU would have received for the traditional expenditure, rather than the cost of the DER alternative. (May 9 Response of Vote Solar, p. 12). This approach has intuitive appeal, but to apply it would require a reasonably firm estimate of the annual avoided cost of the "counterfactual" utility expenditure that was not made. The utility will have to make such an estimate and provide it confidentially to the appropriate review group of non-market participants in order to determine if the DER alternative is cost-effective. My principle concern with this approach is the incentive it would give the utility to overstate the cost of the traditional expenditure.

Given that this is only a short-term pilot program, I still tend to favor the more straightforward approach of applying the percentage incentive to the payments made to the DER provider, potentially at a somewhat higher value than might otherwise be offered. But I welcome comments from the parties on which of the two approaches they view as preferable, and why.

My initial proposal suggested that the incentive percentage be set at the high end of the range of the estimated value of "r-minus-k" for the California IOUs, such as 3.5

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[5] If the particular DER selected is already subject to a shareholder incentive mechanism (*e.g.*, energy efficiency), the larger of the two incentives would prevail. A utility would not be allowed to collect a double incentive.

percent. While the use of "r-minus-k" was controversial, the actual numerical figure was less so, although a number of parties suggested that it would need to be higher in order to address the "investment scale" problem mentioned above. Also, the initial proposal suggested a post-tax incentive of 3.5 percent. This is contrary to how this Commission typically formulates incentives on a pre-tax basis, and may be confusing for that reason. A post-tax incentive of 3.5 percent equates to a pre-tax amount of about 6.0 percent. However, as the Coalition of California Utility Employees pointed out, at page 11 of their opening comments, the initial proposal was in error in applying the 3.5 percent to the entire avoided investment, rather than only the equity portion, which averages about 50 percent for the California IOUs. With this correction, the initial proposed incentive would equal 50 percent of 6.0, or 3.0 percent on a pre-tax basis.

Based on the concerns voiced regarding the investment scale problem – that DERs may be noticeably cheaper than the traditional investment that they displace or defer, I now propose a 4 percent pre-tax incentive if that figure is applied to the annual payment for the DER alternative. If the option of instead applying the incentive to the avoided cost of the traditional alternative (discussed above) were to be adopted, on the other hand, the 3 percent pre-tax incentive derived above would apply. Parties commenting on the choice between the two alternative bases for an incentive (DER cost or avoided traditional solution cost) should also address these differing percentages in their comments.

Further, the provision of a regulatory incentive need not be limited to situations where the "avoided cost" for the utility is always a capital expenditure. In some situations the deployment of DERs may lead to the avoidance of higher operations and maintenance expenses or other non-capital costs for the IOU, such as Conservation Voltage Reduction (CVR) savings. Likewise, coordination with "smart inverters" may allow the utilities to avoid certain costs or improve system performance. While in these situations the potential for savings may be more challenging to quantify, I do not wish to exclude such possibilities *a priori*. If the cost of the payment to one or more DER providers, plus the incentive, is less than the cost of the expenses that the utility would otherwise have incurred, ratepayers will still be better off if the utility chooses the DER option. I encourage the IOUs to pursue such opportunities.

C. Proposed Interim Pilot Program of Regulatory Incentives for Deployment of Cost-Effective DERs

I propose to establish a pilot to offer regulatory incentives to the three large IOUs for the deployment of cost-effective DERs which defer or displace capital expenditures in the distribution system, or otherwise reduce system operational costs. The purpose of this pilot is to test how an earnings opportunity affects IOU DER sourcing behavior. The regulatory process for this pilot will be as follows.

First, each IOU would establish a Distribution Planning Advisory Group (DPAG). The purpose of the DPAG is to review and provide feedback to each IOU on distribution projects which can be deferred or displaced by DER procurement. At this time its scope would be limited to supporting this pilot. The DPAG would be supported by an Independent Professional Engineer (IPE) who would advise DPAG participants on the merits of distribution projects identified by an IOU for deferral or displacement. The IPE would be retained in a manner consistent with the rules and practices for retaining an Independent Evaluator, as set forth in relevant Commission decisions.[6] Market participants would be allowed to participate in the DPAG, but could be excluded from any portion of the DPAG that identifies in detail the cost of the specific distribution investments proposed to be avoided. The IOUs would have two months

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[6] The requirements for participation by an IPE in utility solicitations are outlined in Decision (D.)04-12-048 at Finding of Fact 94-95, Ordering Paragraph 28; D.06-05-039 at Finding of Fact 20, Conclusion of Law 3, and Ordering Paragraph 8; D.09-06-050; and D.10-07-042.

following the adoption of this pilot by Commission decision to establish the DPAG and retain an IPE.

Second, each IOU would identify at least two projects wherein the deployment of DERs on its system could displace or defer the need for capital expenditures on traditional distribution infrastructure. The following guidance would be used in identifying projects.

i. Projects should be selected where the solicited DERs have a reasonable chance of being cost-effective. This determination shall be made by the IOU in a manner consistent with the approach to valuation recommended by the Competitive Solicitation Framework Working Group in their August 1, 2016 report.

ii. Projects shall mirror, to the greatest extent possible, Demonstration C under consideration in the DRP. The purpose of this guidance is to provide something resembling a control group, by which the impact of the incentive present in this pilot (but absent in Demonstration C) can be generally inferred.

iii. The deferral/displacement and DER sourcing resulting from this project should be incremental to any DER deployment currently underway.

Once the utility has identified one or more such opportunities, it would convene a meeting of its DPAG to describe and discuss the proposed project, demonstrating how it complied with the prescribed guidelines. The IOUs would have four months following the adoption of this pilot by Commission decision to conclude its identification of pilots and consult the DPAG.

Third, each IOU would submit a Tier 3 advice letter proposing to procure a DER solution for the identified problem. This advice letter would describe in detail the location in question and the system issue that the proposed procurement is intended to address, specifically including the electrical products and/or services that would be sought. The IOU would describe its plan for soliciting DER solutions for the identified problem. The goal should be to achieve the best, most cost-effective DER packages that can be obtained at the right locations. The IOU would have six months, following the adoption of this pilot by Commission decision, to file its Advice Letter.

Fourth, a public workshop would be held before any comments or protests to the advice letter were due. In that workshop, the IOU would explain the proposed solicitation in sufficient detail for attendees to understand what products and/or services the company is seeking, where, and for what purpose. Proposed attributes and performance requirements for any selected DERs would also be presented for discussion. Parties would be invited to suggest alternative approaches. After the workshop(s), Energy Division would set a deadline for the submission of comments or protests to the advice letter. Energy Division would then prepare a resolution for Commission consideration, addressing any issues raised in comments. The Resolution would pre-approve the annual expenses incurred by the IOU in sourcing DERs pursuant to the projects and an incentive consistent with guidance provided herein.[7]

Fifth, if the advice letter is approved (with or without modifications), the IOU would then undertake the approved solicitation process. The solicitation would follow any rules adopted pursuant to the Competitive Solicitation Framework Working Group's recommendation, filed in this docket on August 1, 2016.[8] These guidelines

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[7] The annual costs of the DERs selected would be reflected in rates in the utility's next General Rate Case (GRC), as discussed below.

[8] If adopted, the final pilot will reflect adopted recommendations from the Competitive Solicitation Framework Working Group.

consist of product definition, counting conventions, solicitation oversight, evaluation, and pro forma contracts. The approval of the advice letter would provide authorization for the utility to procure DER solutions if cost-effective offers are tendered.

Sixth, following the completion of the DER procurement, the IOUs would file a Pilot Evaluation Report. The report would include input from participants in its DPAG and PRG. The report would address the following questions:

(1) Was the solicitation successful in procuring DERs to meet the identified need? A thorough analysis and explanation must be provided, subject to any necessary confidentiality requirements.

(2) How did the earnings opportunity provided in this pilot affect IOU sourcing of DER to defer or displace distribution infrastructure? Was there any measurable difference relative to IOU sourcing for Demonstration C?

(3) Did the DPAG review of IOU project identification have a positive impact on the pilot? Why or why not?

(4) Did the competitive solicitation process perform effectively?

(5) What changes to the pilot would have made it more effective?

The Pilot Evaluation report would be served on the service lists for Rulemaking (R.)14-08-013 and R.14-10-003.

In sum, these six steps result in the following timeline:

Step	Step Duration	Cumulative Duration
1) Establish Distribution Planning Advisory Group (DPAG)	2 months	2 months
2) Identify Projects	2 months	4 months
3) Tier 3 Advice Letter	2 months	6 months

4) Workshop and Protest/Responses	2 months	8 months
5) Resolution	2 months	10 months
6) Solicitation and Contract Execution	4 months	14 months
7) Pilot Evaluation	3 months	17 months

The Commission would actively monitor the pilot and make mid-course corrections as necessary. The deadlines prescribed herein could be altered by the Executive Director.

If the solicitation is successful, the utility would be authorized to record the value of the incentive in a balancing account for later recovery. There would be a review in the Energy Resource Recovery Account (ERRA) compliance application for each year in which an incentive was claimed. The incentive would be recoverable so long as the DERs procured were successful in avoiding or deferring an otherwise planned utility expenditure. Once the deferral period ends and a traditional investment is made, no incentive would be recovered for that year and going forward.

We will not attempt to extract the cost of any displaced distribution investment from a utility's authorized revenue requirement. Rather, the cost of the annual payments to the DER provider would be considered pre-approved for recovery in the next GRC, and the utility's distribution spending request in that GRC would be scrutinized to ensure that no "double recovery" of traditional distribution spending was authorized.

In most cases the timeline for project identification and DER solicitation is likely to be lengthy enough that the traditional investment alternative would not have been reflected in a prior GRC's revenue requirement. However, even if the traditional investment had arguably already been reflected in attrition year rates, the deployment of cost-effective DERs as an alternative should reduce the utility's costs below those authorized. We will not attempt to recover any authorized spending, nor will the cost of the DER payments (other than a possible incentive) be reflected in rates until the next GRC. With this approach the IOU will be able to retain the savings during the rate case cycle from deploying cheaper DERs in place of the prior authorized distribution spending, providing an additional incentive for cost reduction during the cycle. This treatment parallels the approach adopted by the New York Commission in its May 19, 2016 Ratemaking Order cited above and discussed at page 99 of that Order.

D. Limit of the Pilot's Scope

This pilot reaches into matters of ongoing consideration in other proceedings, especially the DRP. Much of the process here is necessary because the Commission has not yet identified how the DRP process will lead to need determinations for distribution services or locational net benefit analyses. However, to achieve progress in piloting potential incentive mechanisms, this regulatory process would work in parallel with the DRP Demonstration projects.

(END OF ATTACHMENT)