MF1/lil 4/4/2016

FILED
4-04-16
10:55 AM

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)

ASSIGNED COMMISSIONER'S RULING INTRODUCING A DRAFT REGULATORY INCENTIVES PROPOSAL FOR DISCUSSION AND COMMENT

Summary

This assigned Commissioner Ruling introduces a regulatory incentive proposal addressing issues related to the issues of "utility role, business models and financial interest with respect to distributed energy resources deployment," as reflected in the February 26, 2016 Joint Assigned Commissioner and Administrative Law Judge Ruling and Amended Scoping Memo (Amended Scoping Memo). Parties are invited to comment on the proposal and respond to several questions provided below. Comments and responses to the questions shall be filed no later than May 2, 2016. Reply comments may be filed not later than May 16, 2016.

Discussion

During the course of this proceeding a number of parties have requested that the Commission address concerns regarding the current regulatory framework and utility business model as they relate to the expanded deployment of distributed energy resources (DERs). Reflecting these party positions, the

Amended Scoping Memo included issues related to the "Utility role, business models, and financial interest with respect to DER deployment." This ruling begins formal consideration of these issues with the intent to begin limited deployment of solutions starting as soon as practical.

I note that concerns regarding the current regulatory framework and utility business model as they relate to the expanded deployment of DERs have also been identified as an issue within the scope of Rulemaking (R.) 14-08-013, the Distribution Resource Plan (DRP) proceeding. Indeed these concerns are integral to the success of both the DRP this and the proceedings. As such, this effort will be closely coordinated with the Assigned Commissioner and Administrative Law Judge of that proceeding.

Consistent with our "walk, jog, run" approach to these complex issues, I do not intend for this phase to consider or adopt an entirely new regulatory framework or business model for the California electric utilities. Rather, I hope to develop a pilot program that can test a revised framework that may assist us in our efforts to promote the cost-effective deployment of DERs in California. At the same time, the critical efforts to further our understanding of distribution planning and the potential value of DERs in R.14-08-013 and to improve the sourcing of DERs in R.14-10-003 must continue on pace.

This ruling represents a first step, wherein I offer a conceptual outline of the utilities' financial interests as they concern DER and a proposed interim regulatory process by which to pilot the effect of incentives on utility sourcing of DER. For now, I will focus on developing a general methodology for calculating incentives. Determining actual incentives earned will require additional steps, including input from stakeholders.

A. Need for Considering Utility Incentives to Deploy DERs

Any regulatory effort that considers displacing or deferring utility investments in distribution infrastructure via the deployment of DERs raises fundamental questions about the current regulatory framework and utility business model. Under the current framework, Investor-Owned Utilities (IOUs) earn a rate of return on investments in utility infrastructure, and distribution infrastructure in particular is a major source of investment opportunity for the utilities today. If the utility displaces or defers such investments by instead procuring DER services from others, it earns no return on the associated expenditures -- such operating expenses are merely a pass-through in rates.[1] Thus, asking the IOUs to identify opportunities for such displacements or deferrals, as we are doing in this proceeding and the DRP, sets up a potential conflict with the company's fundamental financial objectives. If we hope to create a truly successful model for future distribution infrastructure planning and DER deployment, we cannot reasonably proceed without acknowledging and attempting to address the conflict between the Commission's policy objectives and the utilities' financial imperatives. This Ruling sets forth a proposal for a pilot regulatory incentive structure and process designed to harmonize the utility's financial objectives with the Commission's desire to foster the cost-effective deployment of DERs. I seek party comment on this proposed pilot through this Ruling. Before laying out the framework of the proposal, however, I first discuss with more specificity the nature of the utility's current

[1] "Pass-through" may not technically be the correct term if such expenditures are adopted as forecasts in a General Rate Case (GRC). In that case the utility may or may not recover its actual expenses dollar-for-dollar, depending upon how actual costs compare to the adopted forecast.

financial incentive structure, because a thorough understanding of the status quo is essential to any successful proposal for change.

B. The Driver of Increased Shareholder Value:

Return on Equity minus the Cost of Capital, or "*r minus k*"

Attached to this Ruling as Appendices A and B are two articles that discuss in detail the current utility business model with respect to the creation of increased shareholder value. I will not repeat that entire discussion here, but ask for parties to carefully review and comment on whether the observations therein are correct, and if they are not, then why not? The following excerpts from Appendices A and B capture the key messages that I derive from my own review of these articles. This begins by acknowledging roadblocks, in concept, to understanding utility financial value:[2]

> There are two roadblocks . . . to understanding financial value. Many in the regulatory community believe that: (1) the utility's return on equity is the sole value driver; and (2) regulators set returns on equity at a rate equal to the cost of equity. Neither of these perceptions is correct, and understanding why is key to developing effective utility incentive mechanisms.
>
> **THE VALUE ENGINE: *(r-k)***
>
> Many regulatory reform discussions focus on the utility's return on equity as the sole driver of financial value, but that does not align with the concept of investor value creation. **It is not the *absolute* level of a company's return on equity (*r*), but rather the *difference* between *r* and its cost of equity (*k*), that creates the value opportunity that drives the stock price.**
> (Appendix B, p.6)

---

[2] All footnotes and references have been deleted for ease of reading.

This discussion leads to the following correction to the investment incentive proposition espoused by many:

> INCORRECT: $r > 0$ utilities have an incentive to expand
> CORRECT: $r > k$ utilities have an incentive to expand
> $r = k$ utilities are indifferent as to whether they expand
> $r < k$ utilities have a disincentive to expand
>
> Capital, like any other input to a production process, is not free. This should have intuitive appeal. Does it seem likely that utilities would rush to expand their facilities if regulators allow them to earn, for example, a 2 percent return on such investment? Clearly there is some minimum acceptable level of return. The cost of capital, by definition, is that minimum return hurdle.
>
> This corrected incentive structure should give some readers pause. Many, if not most, regulators say that they set utility rates of return equal to the cost of capital. If that condition held, utility management focused on creating value should not care whether it ever makes any plant investment. Just as buying apples for 50 cents and selling them for 50 cents creates no value for the grocery store owner, raising capital at a cost of 10 percent to invest in assets that earn 10 percent is similarly a financial wash—no matter how large the investment, it creates no investor value. (Appendix A, p.3)
>
> If markets or regulators consistently drove the return on equity down to the cost of equity, there would be no financial reason for value-oriented firms to make investments. For a utility, they would have no incentive to invest in new plant.
>
> When return on invested capital is lower than the company's cost of capital, faster growth necessarily destroys value, making the point where return on invested capital equals the cost of capital the dividing line between creating and destroying value through growth. On the line, value is neither created nor destroyed, regardless of how fast the company grows.
>
> The key question for investors then is not whether the utility earns a return on equity on its new plant investment, but whether

> that return exceeds the cost of equity, and by how much. (Appendix B, p.7)
>
> Currently, utilities are typically assigned returns on equity around ten percent, while market evidence and investment analysts suggest that the *cost* of equity for electric utilities today is closer to seven or eight percent. Standard stock valuation models, the ones used by Wall Street investment analysts, demonstrate that today's typical electric utility stock market-to-book ratio of 1.7 is consistent with a cost of equity of 7.5 percent.
>
> To be clear, we are not suggesting in principle it is inappropriate for a utility to be allowed to earn an equity return in excess of the cost of equity—to the contrary, the return on equity *should* exceed the cost of equity, just as it does for the typical non-regulated company. In fact, that is the only way that firms can create value for their investors. Our recommendation is that utility regulators connect this engine of shareholder-value creation more closely to customer- and societal-value creation. A utility earning a rate of return in the ten percent range is earning noticeably more than its cost of equity on every investment. The implications here are important. This system of compensation is predicated on the assumption that nearly all, if not all, **utilities are creating investor value every time they make capital investments**. (Appendix B, pp.4-5)

In short, the utility's incentive to invest is determined by r minus k. Since in recent years r has consistently exceeded k by roughly 2.5 to 3.5 percentage points[3] in California as well as nationally, the incentive to invest additional capital in the utility business has been strong. If this Commission desires to incent the IOUs to displace some of that investment by procuring DERs, it should

---

[3] The 2.5% number comes from the figures quoted from the Appendices: r = 10% and k = 7.5%. The 3.5% is included for conservatism and to reflect California-specific conditions.

offer utility shareholders the opportunity to achieve equal or greater value by so doing. This suggests that IOUs could be incented to pursue DERs if they could achieve shareholder returns equal to, say, 3.5% when they choose DERs over more traditional rate base investments.[4]

The goal of this ruling is NOT to determine the precise value of the incentive; rather, my objective at this point is to determine whether the concept is correct and, if so, how it could be utilized to develop an interim pilot program encouraging the IOUs to pursue cost-effective DERs. If the concept is adopted, the next step would be to establish a methodology to determine k and the appropriate incentive rate relative to the difference between r and k.

C. 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? The problem is that, given the complexity of the distribution system, this Commission is ill-equipped, at least at present, to determine with the necessary specificity exactly when and where such DER deployment opportunities may exist. Further, the regulatory process necessary to make such determinations may be so lengthy, detailed and contentious that the underlying data would become stale before any decision could be reached. Practically speaking, command-and-control regulation faces major challenges in this context. Instead, if our objectives are to be achieved, we should create the

[4] Since utility equity returns on rate base are grossed up to cover the associated state and federal income taxes, an incentive such as that suggested here would also have to be grossed up for taxes.

appropriate utility incentives, such that the IOUs will affirmatively seek opportunities to deploy DERs in the pursuit of their own shareholders' 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[5], 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 Locational Net Benefit Analysis (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 consumers 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. But a difficulty arises when the amount of the savings is uncertain and subject to dispute. Such determinations necessarily involve the creation of a counter-factual: what would have happened, for example, if the DER option had not been pursued? Would the utility actually have proceeded with a different course of action, such as a capital investment? And if so, how much would that alternative have cost? Our experience with shareholder incentives for energy efficiency has been fraught with controversies over such issues, and the situation

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

here is even more complex. While such a determination may still be necessary under the proposed approach in order to set a cost cap on the sum of the utility's DER procurement costs and associated incentives, the exact dollar amount of the foregone capital investment will have far less importance. 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.[6]

For this reason the proposed pilot would offer a shareholder incentive for the deployment of cost-effective DERs that displace or defer a utility expenditure, based on a fixed percentage of the payment made to the DER provider (customer or vendor).[7] The percentage would 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% in the above example. Again, I reiterate that the next step, following the pilot, would be to determine a methodology whereby *r* and *k* could be determined iteratively and, to the extent feasible, automatically. Further, I propose that the exact amount of the incentive be determined in a subsequent ratesetting proceeding. That proceeding may be an extension of this rulemaking,

---

[6] If a party believes that an alternative incentive approach such as split-the-savings is indeed preferable and feasible to implement in the context of this interim pilot, they are welcome to provide comments describing and justifying that alternative.

[7] If the particular DER selected is already subject to a shareholder incentive mechanism (*e.g.*, energy efficiency), the incentive proposed here would prevail over the resource-specific incentive. A utility would not be allowed to collect a double incentive.

an addition to a related rulemaking (*e.g.*, DRP), or part of a utility request for cost recovery following the execution of DER sourcing. The proposed interim process, outlined below, suggests the latter.

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. 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.

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

I propose to establish, on a pilot basis, an interim program offering regulatory incentives to the three large IOUs for the deployment of cost-effective DERs. In this context, "cost-effective" means that the DERs plus the incentive cost less, in terms of present value of revenue requirements, than what the utility would have recovered if it had not deployed the DERs. In appropriate circumstances, this may also include system level costs for the procurement of energy, capacity and ancillary services, as well as the cost of Greenhouse Gas emissions avoided by the choice of the DERs. For purposes of discussion, please assume that the incentive would take the form of an additional payment to the utility of 3.5% (grossed up for taxes) of the payments made to the DER provider(s). The exact figure will be determined later if this proposal or a similar alternative is adopted by this Commission.

The regulatory process for identifying opportunities for cost-effective DER deployment, selecting, deploying and verifying them, and awarding incentives must also be determined. What follows is my suggested process structure, which may be modified or replaced based on the comments received. Much of the process here should eventually be displaced by the DRP process, which I broadly envision to include: a) application of the Integrated Capacity Analysis and LNBA methodologies at regular intervals, b) approval of resulting determinations of distribution service needs and opportunities, and c) approval of authority to source incremental DERs to meet distribution service needs and opportunities. However, to achieve progress in piloting potential incentive mechanisms, I propose a pilot in this proceeding in order to test incentives in parallel with the DRP Demonstration projects.

The proposed pilot process would function as follows: First, the utilities would begin to identify opportunities for the cost-effective deployment of DERs on their systems. Once the utility has identified one or more such opportunities, it would convene a meeting of its Distribution Planning Review Group (DPRG), a new entity similar to the existing Procurement Review Group (PRG) but with differing membership,[8] to describe and discuss the proposed DER procurement.

Second, following this consultation, the utility would submit a Tier 3 advice letter proposing to procure DERs. This advice letter would identify in detail the location in question and the system issue that the proposed procurement was intended to address, specifically including the electrical

[8] The DPRG would be open to interested non-market participant stakeholders that are willing to enter into an appropriate non-disclosure agreement, and would include Office of Ratepayer Advocates (ORA) and Energy Division.

products and/or services that would be sought. A cost estimate for the action that the utility would propose to take in the absence of a DER solution would also be provided to the DPRG and the Commission on a confidential basis. The utility would describe its plan for soliciting DER solutions to the identified problem. At this stage, all-source RFOs for DERs consistent with the solicitation framework being developed in this proceeding would be our preferred procurement vehicle. The goal should be to achieve the best, most cost-effective DER packages that can be obtained, at the right locations.

The utility would also describe in its advice letter a proposal for notifying end-use customers in the affected area of the electrical products and/or services the utility was seeking to obtain. Affected customers could propose their own DER projects or, more likely, various vendors and aggregators could offer packages of DERs in the defined area. Customers in the affected area could also indicate that they would like to have their names and contact information placed on a public list that vendors could use to solicit participants in a DER project. Absent such affirmative consent, the identities of individual customers in the affected area would not be disclosed.

Third, a public workshop would be held before any comments or protests to the advice letter were due (in other words, the standard protest period would be extended), and in that workshop the utility would explain the proposed solicitation in sufficient detail for attendees to understand what products and/or services the company was seeking, where, and for what purpose. Proposed performance requirements for any selected DERs would also be presented for discussion. Parties would be invited (and encouraged) to suggest alternative approaches.

Fourth, after the workshop(s), a deadline of a certain number of days would be set for the submission of comments or protests to the advice letter. (The deadline could be determined by the Commission or could be flexibly determined by Energy Division.) Energy Division would then prepare a resolution for Commission consideration, addressing any issues raised in comments.

Fifth, if the advice letter is approved (with or without modifications) the utility would then undertake the approved procurement process, in consultation with its DPRG and an independent evaluator.

Sixth, any resulting contracts would be submitted for Commission approval via an application, in which the utility would justify the chosen DERs and propose an appropriate incentive, consistent with the Commission's prior guidance. If a DER solution is chosen and approved, the utility would be authorized to record the approved shareholder incentive in a balancing account at the same time as payments were made to the DER provider, and entries to the account would be subject to review in a designated subsequent formal proceeding. The presumption would be that the utility would be able to collect the incentive as long as a potential distribution capital investment or expenditure was, in fact, deferred at a cost less than that of the avoided utility expenditure. I anticipate that ORA and other traditional GRC intervenors would be involved in ensuring consistency among DRP results, GRC requests, and claims for successful deferrals.

During the interim period, while this process proceeds in parallel with the DRP Demonstration projects, I envision that a utility could submit the initial Tier 3 advice letters as often as necessary, hopefully grouping several identified projects together to avoid multiple, overlapping requests. A potential minimum requirement of at least one proposed project every six months could be established to ensure that the program is actually implemented, but I would hope and expect that the utilities would be more aggressive in seeking out DER deployment opportunities.

I offer this proposed process as a straw man for discussion and comment, and am open to suggestions for how to improve and/or expedite the process of proposing, reviewing and approving of potential DER deployment opportunities, consistent with the need for adequate review and comment by both market and non-market participants.

At this time I foresee this pilot opportunity lasting for no more than two years from initial approval through the date of the last advice letter proposal, although actual project development may take longer. The Commission will actively monitor any approved pilot and make mid-course corrections as necessary. Once the DRP process for determining distribution service needs and opportunities is up and running, this program could potentially be made permanent (with or without modification) if it proves to be successful.

E. Request for Comment

Comments on all aspects of this proposal, including the Appendices, are invited, to be filed no later than May 2, 2016. Suggestions for modification or entire alternative proposals are welcome. Reply comments may be filed no later than May 16, 2016. One or more public workshops may be scheduled once the initial comments have been submitted and reviewed, and will provide for at least one round of post-workshop comments, if not more. The assigned commissioner and/or assigned Administrative Law Judge will modify the schedule as necessary.

Specific questions that I would like parties to address in their comments include the following:

1) Is the description of the source of utility shareholder value summarized above and discussed in the Appendices accurate? If not, why not?
2) Would an incentive program such as that described above achieve the objective of promoting the cost-effective deployment of DERs? If not, why not?
3) What alternative approaches should the Commission consider at this time?
4) Is the proposed incentive, in the range of 3.5% grossed up for taxes, approximately correct?
5) Are there other disincentives to the deployment of DERs that this proposal does not address that should be considered at the same time? If so, please explain.
6) Is the suggested process for identifying and approving DER projects that would generate an incentive reasonable and appropriate? How could the process be improved?
7) Is there need for a limit on the number of projects or the amount of dollars that a utility could propose during this pilot program? If so, what should it be?
8) Would participation in a DER solicitation by a utility affiliate require any changes to the Affiliate Transaction Rules, or any changes to the process for review and approval of proposed DER solutions?
9) What would be the appropriate role of the IOUs themselves in the deployment of cost-effective DERs? Should direct IOU participation in DER deployment be encouraged, foreclosed, or allowed with certain caveats? Please fully explain your answer.

IT IS RULED that parties may file comments to the proposal presented in this assigned Commissioner's Ruling and may respond to the questions posed. The comments and responses shall be filed no later than May 2, 2016. Reply comments may be filed no later than May 16, 2016.

Dated April 4, 2016, at San Francisco, California.

/s/ MICHEL PETER FLORIO
Michel Peter Florio
Assigned Commissioner