BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	Application 15-07-002 Application 15-07-003 Application 15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 796.	Application 15-07-005 (Filed July 1, 2015)
And Related Matters	Application 15-07-007 Application 15-07-008

OPENING COMMENTS OF THE UTILITY REFORM NETWORK CONCERNING THE STAFF WHITE PAPER ON GRID MODERNIZATION

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OPENING COMMENTS OF THE UTILITY REFORM NETWORK CONCERNING THE STAFF WHITE PAPER ON GRID MODERNIZATION

Pursuant to the directions in the Assigned Commissioner's Ruling (ACR) of May 16, 2017, the Utility Reform Network (TURN) respectfully submits these opening comments in response to the "Staff White Paper on Grid Modernization," included as Attachment A to the ACR.

TURN organizes these comments in order of the sections in the Staff White Paper, and answers some of the stakeholder questions posed in the White Paper in the relevant sections. TURN regrets that we are unable to provide as comprehensive a response, or as well organized a response, as we would like due to multiple other litigation deadlines occurring last week.

1 Summary of Recommendations

TURN applauds the Staff White Paper (SWP) for providing a very good synthesis and theoretical framework regarding the underlying question of how to create a framework and a process to evaluate the grid investments needed to support increased deployment of various distributed energy resources (DERs). As is apparent from some of the text, there are inherent limitations in defining a theoretical framework given that 1) grid assets often serve multiple use cases, and 2) asset needs are extremely localized and granular. As discussed in more detail below, TURN recommends the following:

- In the near term, the general process proposed by staff is reasonable, as long as the Grid Needs Assessment and the Grid Modernization Plan (GMP) are evaluated **together in the general rate case** to ensure all reasonable alternatives to solve an identified problem are considered. The critical step will be the identification of actual "need" in the Grid Needs Assessment (GNA), the choice of the least cost technology/process solution to address those needs, and an evaluation of whether asset investments conducted for other goals (safety, reliability) can be configured to also maximize DER hosting capacity.

- In the long run, separating grid planning for DERs from other grid planning processes is not useful and will lead to sub-optimal solutions. TURN does not agree that utility distribution planning can be readily separated into DER versus reliability versus safety investments, since most assets serve multiple functions and use cases. Over time grid planning should be incorporated into utility risk-informed decision-making, with Grid Modernization Plans providing just one input into the overall process.

- The SWP should clarify how policy goals, investments and cost responsibility may differ for wholesale (in front of meter) versus retail (behind the meter or NEM) DERs. This distinction is important because 1) modeling growth of wholesale capacity additions is difficult; 2) actual problems to date stem primarily from wholesale distributed solar generation projects; and 3) the cost levels and cost responsibility under Rule 21 for NEM versus wholesale projects is fundamentally different. Indeed, the SWP definitions of "net benefits" appear to envision different treatment of net benefits depending on the nature of DER deployment, although the SWP needs clarification on this issue.

- The definition of "grid modernization" should be modified to ensure that it is not suggesting that the utilities must immediately spend anything necessary to create a "plug-and-play" grid.

- TURN has strongly supported ensuring that "net benefits" includes all potential grid investment costs before they become sunk costs. However, TURN can envision that different definitions of "net benefits" could apply to investments needed for "autonomous" NEM DER growth, versus investments to address wholesale DER or DER installed as an alternative to traditional distribution capacity investments.

2 COMMENTS ON SPECIFIC SECTIONS

2.1 Introduction

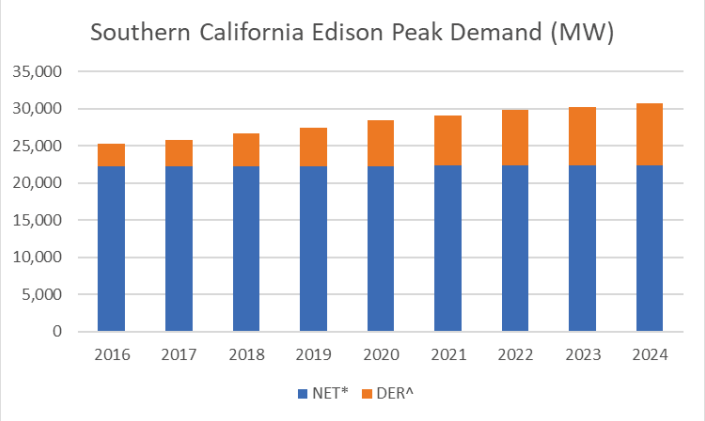
TURN comments on the introduction only because it highlights a theme that is present in the Staff White Paper. Namely, at the very beginning the SWP states unequivocally that: "The growth of DERs adds a new level of complexity to the planning and function of the distribution grid. The current grid can't respond to the operational conditions that are emerging, requiring new technological upgrades to manage the challenges of grid operations."[1] TURN does not at all

[1] Staff White Paper, p. 5.

disagree that DERs present certain challenges and complexities; however, there is no evidence that the grid "cannot respond" absent some "new" technologies or massive upgrades.

The fact is that California is not Hawaii. California has the two largest utilities in the country, while Hawaii has six small isolated grids with rooftop solar penetrations at 20%-30% of peak load in 2013.[2] California is nowhere near the level of DER installation that might jeopardize continued DER growth. For example, SCE forecasts DER growth occurring at a significant but measured pace.

Figure 1: SCE Forecast of Peak Load and DER Growth[3]



Utility upgrades due to NEM projects, summarized in Table 1, have required relatively low expenditures, at least compared to grid modernization proposals, and utility NEM project

[2] See, for example, E3, "Envisioning the Electric Utility in 2030: 'Fat' or 'Skinny'?", September 2016, p. 10-11. Available at: https://www.ethree.com/wp-content/uploads/2017/03/E3_Envisioning-the-Electric-Utility-in-2030.pdf

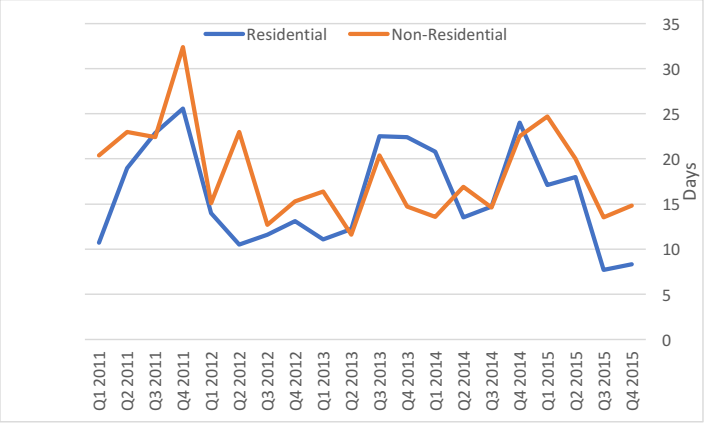
[3] Net load forecast from: California Energy Demand Updated Forecast, 2017-2027. California Energy Commission. December, 2016. P. 30. DER growth from: A.16-09-001, SCE WPSCE02V03RBkA, p. 150.

interconnection times have remained relatively short despite the large increase in the number of projects in 2013-2016, as illustrated for SCE in Figure 2.

Table 1: IOU Reported Costs for Interconnecting NEM Projects and Upgrading the Grid Total About $40 Million for 2013-2016

NEM Upgrade Costs	**Total for Nov. 1, 2013 - July 31, 2016**			
Utility:	**PG&E**	**SCE**	**SDG&E**	**TOTAL**
Sources:	AL 4660	AL 3239	AL 2761	**ALL IOUs**
	AL 4918	AL 3473	AL 2984	
Dist Engineering (rule 21 studies)	$3,711,647	$833,579	$501,929	$5,047,155
Meter Installation/Inspection	$998,645	$667,294	$1,566,842	$3,232,781
Interconnection Facilities	$5,250,277	$10,976,544	$51,870	$16,278,691
Distribution Upgrades	$14,630,565	$1,517,572	$76,771	$16,224,908
Total: Upgrades + Eng + Meter	$24,591,134	$13,994,989	$2,197,412	**$40,783,535**
NEM Interconnections	164,132	142,884	67,937	$374,953
Total Cost/Interconnection	$150	$98	$32	$109

Figure 2: Average Quarterly NEM Interconnection Times for SCE[4]



The introduction also reflects the problematic assumption that grid *modernization* requires "new technological upgrades." While there is nothing wrong with installing "new technologies" when they are more effective and more cost-effective than older ones, TURN's analysis in the SCE rate case (A.16-09-001) found that SCE's grid modernization was more expensive by about a factor of ten due to its intent to install "automation" technologies, whereas installing similar assets with communications capabilities but allowing the control room operator to control the assets, rather than automating asset control, provides the required functionality and all of the benefits at a fraction of the cost.[5] SMUD has conducted a sophisticated grid

[4] Source: Go Solar California, Data Annex (accessed April 18, 2016). PG&E and SDG&E data are similar.

[5] Due to the page limit restriction, TURN does not attach the entire testimony of Paul Alvarez and Dennis Stephens in A.16-09-001. It has been identified as Exhibit TURN-06, and is available on the Commission's supporting documents site for A.16-09-001 at: http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1609001/555/190624017.pdf

modernization analysis[6] and concluded that their "grid modernization" will consist of installing more transformers (for EV load) and voltage regulators (for solar DG). This is the type of grid upgrades that utilities have done for decades based on ongoing and constant changes in customer loads and load mixes, even as the actual equipment improves over time, especially due to the use of solid state electronics and communications.

2.2 Sec. 1.3 – Defining Grid Modernization

Related Stakeholder Questions:
1. Please provide any comment and/or recommended changes to the definition, challenges and opportunities, or objectives of Grid Modernization presented in this section.
2. Based on the definition above, which investments should be characterized as only supporting safety and reliability, and thus, out of scope of this proceeding?

Categorization of investments

It is difficult if not impossible to identify capabilities needed solely for DER accommodation. Insofar as DER presents safety and reliability challenges, investments made to accommodate greater amounts of DER are inextricably linked to safety and reliability. Thus, rather than characterizing safety and reliability as "out of scope" of the DRP proceeding, the issues, solutions testing, and preferred solutions identified in the DRP proceeding would ideally be integrated into utilities' routine grid planning and risk-informed investment prioritization processes as part of periodic rate cases, as guided by the risk-informed processes being presently developed, for example, in the Safety Model Assessment Proceeding.

Again, SCE's current grid modernization proposal illustrates this problem. SCE's "grid modernization" proposal of about $2.1 billion is actually split into two components – a reliability component and a DER component. Each component involves the installation of almost exactly

[6] Black & Veatch and Smart Electric Power Alliance, "Beyond the Meter: Planning the Distributed Energy Future," Vol. II, pp. 21, 30. Available at: https://sepapower.org/resource/beyond-meter-planning-distributed-energy-future-volume-ii/

the same assets – primarily automated switches and cross-ties – in addition to system-wide deployment of communications (FAN, WAN) and IT solutions. The only difference is that SCE targets about 200 circuits per year as "reliability" based on its Worst Performing Circuits list, and then targets about 88 circuits per year as "DER" based on three DER-related criteria (autonomous growth, high LNBA value, deferral projects). Whether these investments are thus "DER related" depends entirely on the accuracy of SCE's circuit selection.

There are many traditional T&D investments that are intended for "reliability," such as "infrastructure replacement" program, and there are "customer-driven" investments that basically expand the distribution grid. However, even those asset replacements/installations may have DER-related impacts, generally by increasing hosting capacity.

Definition of grid modernization

TURN recommends that the staff's definition of the "Grid Modernization" be modified to clarify that allowing for the "seamless interconnection of distributed energy resources" **does not mean** that any DER should be able to be interconnected without any additional grid upgrades necessary for the particular DER. Neither the statute nor the Commission has adopted a "plug-and-play" grid, irrespective of cost, as the objective of grid modernization. Yet one could interpret preemptively upgrading the entire grid to "seamlessly" interconnect anything anywhere as a mandate for a "plug-and-play" grid, which would lead exactly to the "widespread adoption of all grid modernization technologies [that] could far outstrip the benefits they provide."[7] The definition should be modified to state, for example:

[7] Staff White Paper, p. 11.

A modern grid allows for the interconnection for distributed energy resources without undue cost or delay, allowing for reasonable and timely distribution upgrades to be conducted based on project-specific evaluations, and allowing for the differences in impacts of behind-the-meter technologies versus wholesale DER projects, while maximizing ratepayer benefits, minimizing impacts and risks of safety and reliability.

Deleted: *seamless*

TURN emphasizes that the potential of "grid modernization" to swamp the benefits of DER projects is very real. Again, in its rate case SCE proposed to "modernize" 74 circuits due to its four proposed deferral pilots. SCE forecast about $40 million in savings from deferred capital projects, but forecast spending about $80 million on these circuits.[8] Does this make any sense? Either SCE's forecast of savings is completely erroneous, or else its technology choice for "modernization" is overly expensive. TURN believes it is likely the latter.

The key issue will usually be the ultimate choice of technology solutions to address an identified problem. As in all electric distribution endeavors, there are relatively expensive and relatively inexpensive ways to address almost any technical challenge, including the technical challenges presented by increases in DERs. The preferred solution is implemented locally across the grid as the root causes are encountered, and as prioritized by a risk-informed merit process relative to other potential capabilities and investments. Occasionally, system-wide improvements (such as back-end software) will be required.

Use of the Term "DER"

Lastly, TURN recommends greater clarity and specificity regarding the term "DER." It is often used as a shorthand, but such use masks critical and fundamental distinctions between the impacts of NEM distributed generation (retail DG), wholesale DG, storage, demand response

[8] Exh. TURN-06, p. 75-79.

(DR), energy efficiency (EE), and electric vehicles. For example, the SWP states that "Certain DERs such as energy storage, demand response, and electric vehicles provide capabilities needed for the electric grid on a local level that can help integrate the growing intermittent supply of utility-scale renewables."[9] This statement quite correctly differentiates the role of certain DERs, though the phrase "needed for the electric grid on a local level" is confusing. For purposes of "renewable integration," grid storage could be sited at almost any location, including bundled with utility-scale wholesale solar projects interconnected at the transmission level.

More confusingly, in the same paragraph the SWP goes on to say that "the rapid adoption of DERs also increases the complexity of the electric system and impacts how the grid is operated." This general reference to "DERs" masks the fact that DR and EE do **not** increase complexity any more than typical demand-side load changes that utilities have addressed for decades. Moreover, DG and EV have quite different, and potentially opposite, impacts on grid operations, with EV representing large demand growth that is not stationary at different locations. Moreover, even the impacts of wholesale and retail DG are quite different. TURN fully appreciates that it is impossible to differentiate these different impacts with every phrase that uses "DERs," but TURN strongly believes that a paper designed to address utility grid modernization in response to DERs should at the least have one section, or side-box, that distinguishes the potential impacts, or lack thereof, of different "DERs." This is simply the first step in naming and identifying potential problems and grid needs.

2.3 Sec. 2 – Classification and Framework

Related Stakeholder Questions:
3. Does this classification framework, with the 5 sets of categories, accurately frame grid modernization technologies for the purpose of clarification and evaluation of grid needs? If not, how could grid modernization proposals be more effectively framed?

[9] SWP, p. 10-11.

4. Are the categories of use cases, technologies, functions and other classification accurate and complete? If not, what should be added or modified?
5. Are the Appendices accurate and complete? If not, what should be added or modified?

Appendices

In response to questions 4 and 5, TURN recommends two modifications to the Appendices. First, TURN recommends adding the following two items to Appendices A, B, and C:

- Access to and use of Wholesale DER facility data in near-real time;
- Access to and use of grid section-specific historical/modeled 8760 load data.

Near-real time telemetry information from large, wholesale DER facilities (and perhaps eventually from rooftop facilities) is absent from Figure 2. This information is critical to DER accommodation and future grid operations. Information on grid loads as they change throughout the day – modeled for each grid segment for 8,760 hours per year – can also play an important role in optimizing grid operations for DERs and addressing safety and reliability issues related to DERs *for the least possible grid investment*.

Second, TURN recommends that the term "Intelligent Automated Switches" be replaced with the more generic "remote controlled switches." One of the key findings in TURN's testimony in the SCE GRC is that there is a huge cost difference, without a corresponding functionality benefits difference, between grid "automated switches" and full "automation," versus increasing communications from devices for rapid response time.

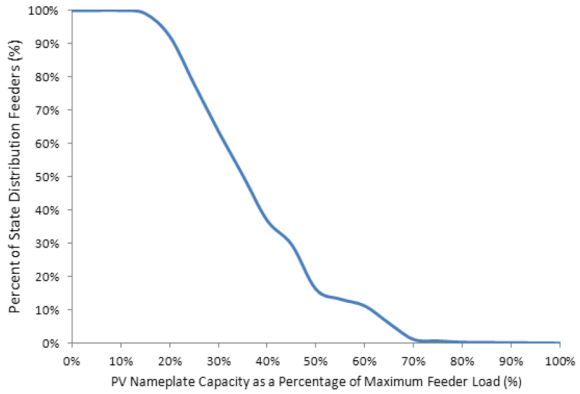
TURN agrees that increased flexibility, to be facilitated by a more networked grid layout, remote-controlled switching, and increased grid state visibility (which is in turn facilitated by remote fault indicators and grid state information), should be a big part of grid planning and

operation in the future.[10] However, TURN does not agree that this increased grid flexibility must be automated to be effective. TURN's analyses of SCE's grid automation proposal found that the very large additional costs required to automate grid flexibility from a centralized location – including the related incremental costs to upgrade the FAN, the WAN, substation automation, and back-office software such as a Grid Management System – were in no way justified by the incremental benefits of such automation.[11]

At page 16 staff reiterates that "As more DERs interconnect to the distribution system, the impact they have in aggregate on distribution grid operations will become increasingly significant." TURN does not disagree with this general conclusion, but TURN cautions that the system is far from any generic integration challenges. Even more importantly, most challenges are extremely circuit-specific, which means that "systemwide" solutions must be evaluated very carefully to ensure they are necessary. For example, while much is made of the potential problem of "two-way flow," a study done using actual IOU data minimum feeder hourly loads, found that with a "no backflow" criterion more than 60% of feeders could support PV capacity at 30% of peak feeder load, and approximately 10% could support PV capacity up to 60% of peak load.[12]

[10] A.16-09-001, Exh. TURN-06, p. 67-71.
[11] A.16-09-001, Exh. TURN-06, p. 79-88.
[12] E3, "Technical Potential for Local Distributed Photovoltaics in California: Preliminary Assessment," March 2012, p. 32-33. Available on the CPUC website at: http://www.cpuc.ca.gov/rps_reports_docs/ . The utilities presently use a 15% of peak load criterion as a screen under Rule 21.

Figure 3: Maximum PV Penetration without Backflow on California Distribution Feeders



TURN's analysis in the PG&E GRC reached a very similar conclusion.

2.4 SEC. 3.1 – Planning Process

Related Stakeholder Questions:
6. Are the proposed steps in the grid modernization planning process reasonable and appropriate? If not, what should be modified? (p. 21)

Use of Rule 21 Interconnection Process

At page 18, the SWP describes that presently DER integration-related investments are primarily implemented on an "as-needed basis through the Rule 21 interconnection process." TURN agrees, and further suggests that the Rule 21 process as presently conducted is actually completely adequate to cost-effectively address the integration of large amounts of retail (NEM) distributed generation. As shown in Table 1 and Figure 2, retail NEM projects of up to 1 MW in size have been successfully connected at low costs and rapid interconnection times even while the number of projects grew dramatically in 2013-2016.

For wholesale projects, TURN cannot readily evaluate the efficacy of the Rule 21 process. TURN has not participated actively in the Rule 21 process, and so cannot evaluate how the changes adopted in the past few years[13] have functioned to expedite interconnections. However, while the focus of the Rule 21 process has been to reform elements that raise roadblocks and difficulties for DG developers, TURN is concerned that conversely Rule 21 as it is currently constituted does not adequately charge wholesale DG developers for all necessary upgrade costs. While the immediately-required upgrades associated with the interconnection of wholesale DER facilities to the grid are being charged to developers at cost per Rule 21, there is a cumulative effect of multiple tranches of wholesale DER generation on grid capacity and operations which may not be currently recognized under Rule 21.

New Planning Process

The SWP proposes a process that relies on using the tools being developed in this DRP – growth scenario forecasts, ICA analysis of circuit hosting capacity, and LNBA analysis – to provide a detailed description of the circuit-specific growth forecast and ability to host DERs. This detailed analysis would then form the foundation for a Grid Needs Assessment and a Grid Modernization Plan.

Such a process seems logical and effective. Nevertheless, TURN continues to have reservations about segregating grid modernization planning into a separate process apart from the planning for other grid investments related to new capacity, aging infrastructure replacement, load growth, etc. TURN is concerned that segregating distribution planning just for DERs could

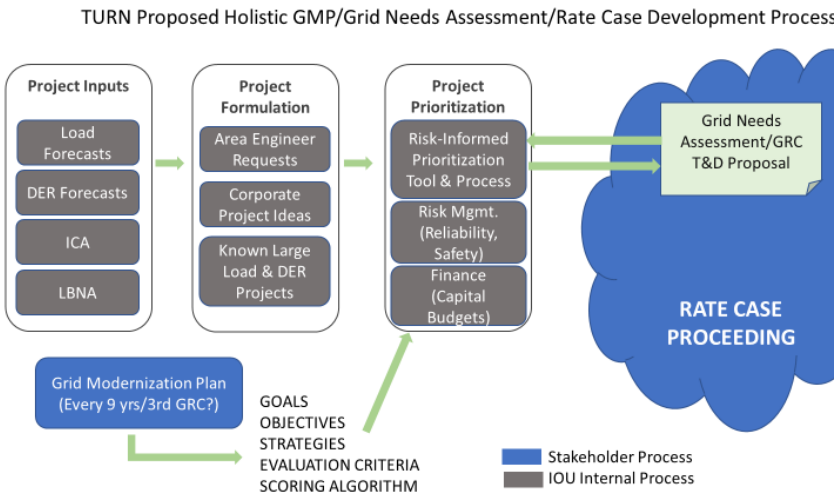
[13] D.14-04-003 (distribution group study process); D.16-06-052 (adopting pilot cost envelope process).

be counter-productive and could result in premature, unnecessary, and ill-informed prioritization of distribution investments.

In the short term, TURN supports the staff proposal. However, in the longer term, TURN envisions a process where all utility distribution planning and investments are prioritized based on risk-informed decision-making that addresses how to allocate limited utility budgets to best meet safety, reliability and DER integration goals. Periodic Grid Modernization Plans should be used to update formal risk-informed prioritization evaluation criteria and scoring methodologies. Then rate case proceedings would become a stakeholder process to determine the size of the capital budget necessary to achieve prioritized goals. With the benefit of the Grid Needs Assessment (a product of the risk-informed prioritization process), stakeholders could help make this determination with an understanding of priorities and trade-offs.

The accommodation of Distributed Energy Resources is already becoming a permanent expectation of an electric distribution utility's responsibilities. It will increasingly become "business as usual" in both periodic grid planning exercises, GRCs, and day-to-day operations. Investments to accommodate higher levels of DERs and other grid objectives should be considered as part of a routine, periodic risk-informed capability and investment prioritization process. In the long run, the Grid Modernization Plan could be updated at some longer interval to establish the balance of priorities between reliability, safety, and DER objectives via the determination of evaluation criteria and scoring methodologies to be used in the risk-informed prioritization tool and process. The GMP would be an input into more frequent risk-based project prioritization processes, as illustrated in Figure 4:

Figure 4: TURN Proposal for the GNA/GMP/GRC Process



TURN recommends the risk-informed prioritization process be documented and open to stakeholder review and input as part of each IOU's GRC. The five steps proposed in the SWP would be entirely appropriate to serve as part of that documentation. However, this documentation should be just one component of a comprehensive grid planning and prioritization exercise.

2.5 SEC. 3.2 – Review Of Grid Needs

Related Stakeholder Questions:
7. What types of information and level of detail should the IOUs include in the GNA? (p. 23)
8. Should the Grid Needs Assessment be formally filed, or only made available for informal review? If formally filed, what is the appropriate procedural vehicle? (e.g., Advice Letter, Motion, Application)? (p. 23)
9. How can the timing of the GNAs, GMPs, and GRCs be best coordinated? How should the Grid Needs Assessment inform the GMP? (p. 23)

10. Is this schema an appropriate method to prioritize locational needs and proposed investments? How should it otherwise be modified, or what would be an alternative approach to identifying locational priorities? (p. 24)

Information for Grid Needs Assessment

Developing a Grid Needs Assessment will be a critical component, since defining any grid needs or challenges will be a key step. The general description of the GNA sounds reasonable. The level of detail required of IOUs in a GNA should be similar to the level of detail available from a completed risk-informed prioritization process, including:

- The evaluation criteria and scoring methodology to be applied to identified capabilities and investments, along with any weightings, assumptions, or other determinants;
- The full list of capabilities and investments (projects) considered for the GNA and associated risk-informed prioritization scores;
- The same list ranked by the risk-informed prioritization score for each project;
- The proposed capital budget (which establishes a "line" in the ranked list; projects above the line are selected for implementation). Reductions in the capital budget reduce the projects to be implemented, while increases in the capital budget increase the projects to be implemented;
- Any requested exceptions (projects which score "below the line" but have been prioritized for implementation by the IOU) and associated justifications.

Coordination of GNA, GMP and GRC:

One of TURN's primary recommendations is that the GNA and the GMP should be formally reviewed together in the utility rate case. It may make sense to submit the GNA informally in advance, so parties can have additional time to review. However, it is essential that the formal review occur at the same time. It is a recipe for disaster to attempt to "authorize" a GNA or a GMP separately, without considering together what technology choices are being selected to address which identified needs.

An initial GMP could serve as a guideline for future plans. The initial GMP should propose an evaluation criteria/scoring methodology, which would be completed periodically in advance of a GRC in combination with the SMAP proceedings or as part of a combined SMAP/DRP/GMP proceeding.

Schema for Locational Needs

The proposed schema makes logical sense, though TURN is extremely concerned about any "proactive" upgrades based on forecasted DER growth. TURN still believes that extending existing utility grid planning processes to account for differential impacts of DER and finding least-cost solutions is a workable method for the time being, and massive "preemptive" investments should not be made based on uncertain forecasts. The key is to upgrade circuits sufficiently fast to avoid undue interconnection delays, but no so far in advance as to strand investments if growth forecasts prove erroneous. This is the classic problem in large generation investments. The whole point of DERs is that they are smaller, and are installed faster, so there should be less need to make massive mistakes up front.

To the extent a schema is used, it should still account for the difference between retail and wholesale DER. For example, Location F (Low hosting capacity, low net benefits, high penetration) is a Priority 2 location in the schema. Practically, low hosting capacity and low net benefits could describe a rural circuit with low peak load. An important question is whether the "high penetration" forecasted for DER is retail DG or wholesale solar DG? These are precisely the types of locations where wholesale DG has historically been sited, due to lower land costs, but where such installations may result in backflow or other distribution impacts. Upgrading such locations in advance is simply a subsidy to wholesale developers, who then do not have to include any upgrade costs in competitive bids.

2.6 SEC. 3.3 – Grid Modernization Plans

Related Stakeholder Questions:
11. Should the Grid Modernization Plans include information on both location-specific and systemwide proposed investments or should they focus on systemwide proposals? (p. 25)
12. What additional or different information should the IOUs submit as part of the Grid Modernization Plans? (p. 25)
13. Which option should be implemented and why? How could these options be modified? Are there other options that should be considered? (p. 28)

14. If you recommend an option that requires the utilities to file GMPs in advance of their GRC applications, how far in advance should the GMPs be filed to allow for adequate review? (p. 28)
15. As an alternative to filing GMPs every three years, should the GMPs provide a more general blueprint of proposed grid investments over a longer timeframe? (p. 28)

TURN suggests that all grid modernization investments – both local and systemwide – should be included in the GMP.

As discussed above, TURN strongly recommends that in the short term the GMP be reviewed together with the GNA in the utility rate case. Thus, TURN recommends the use of either Option 1 or Option 2.

TURN recommends that the initial GMP should provide a more general blueprint of proposed grid investments over a longer timeframe, ideally to include the evaluation criteria and scoring methodology to be applied to all grid investment proposals, including goals (DER, reliability, safety, etc.), weightings, etc. In this manner the GMPs can inform the Grid Needs Assessments/Risk-Informed prioritization process which would be part of future rate cases. A periodic update of the GMPs may be advisable.

TURN is concerned that the Commission has expanded the goals of the distribution resource plans, and associated grid modernization investments, beyond the original intent of § 769. The statutory provisions of AB 327 focused on utilities identifying "spending necessary to integrate cost-effective distributed resources," with the cost-effectiveness based on the notion that deploying DERs in "optimal locations" would actually lower net costs to ratepayers by deferring other distribution investments. However, the Commission expanded the goals of the DRP to include accommodating "two-way flows" and "enabling customer choice."[14] The Commission recognized that "a significant component of the net benefit calculation will be

[14] ACR, February 16, 2015, p. 2-4.

whether deeper penetration of DER in a particular location or on a specific feeder will be able to provide an alternative to the more costly upgrades of distribution (or eventually transmission) facilities that might otherwise be necessary to meet load."[15]

TURN is concerned that this consideration has been largely forgotten. The SWP lays out a process that could allow the utilities to sink significant distribution investments that would never be counted in a net benefits analysis, but might also never produce the benefits of deferred or avoided utility investments. We are now in an era where utility profits are derived primarily from distribution investments, where California distribution rates are growing faster than for any other utility in the country, and where high distribution rates reduce the ability of CCAs to compete on price. The Commission should not allow "DER accommodation" to become an excuse for massive utility profits that have nothing to do with maximizing "cost-effective DERs" or net benefits. The goal should be to achieve the most DER growth at the least cost (or with "net benefits") to ratepayers, not to promote DERs at any cost based on a belief in future benefits.

2.7 SEC. 3.4 – Cost Reasonableness

Related Stakeholder Questions:
16. Are there any additional approaches to assessing net benefits that should be considered?
17. Which of the above options should be applied and why?
18. Is the table of costs and benefits in Figure 3 complete and accurate? How could Figure 3 be modified? What cost and benefit information should be provided to the Commission for analysis?

The question of how to measure "net benefits" is difficult in theory, and even more difficult in practice. The SWP lays out three options for meeting the objective of § 769(b)(4), which requires the utilities' distribution resources plans to "identify any additional utility spending ... with the goal of yielding net benefits to ratepayers." Prior to describing the three

[15] ACR, February 16, 2015, p. 4.

options, the SWP explains that there are two different methods of defining "net benefits."[16] The SWP does not any ask stakeholders to comment on these definitions. However, the choice of these two definitions is one of the key policy directives that should be provided in this proceeding.

Definition of Net Benefits

TURN has repeatedly argued that any "net benefits" analysis must 1) use the LNBA to calculate benefits; and 2) consider all potential utility modernization investments before they become sunk costs. This approach is consistent with the second definition proposed in the SWP. However, in reviewing the definitions of "net benefits," TURN finds that the first proposed definition ("support autonomous DER growth") could be workable if applied only to grid modernization for "autonomous DER growth," which should only be considered to be **retail NEM growth**. To date, NEM growth has been effectively supported by upgrading the grid due to individual projects consistent with Rule 21. In SCE's rate case, SCE proposed to upgrade 63 circuits (out of its total of 263) due to "organic growth," which is synonymous with "autonomous growth." Significantly, TURN did not object to upgrading 54 of those circuits, aside from 9 circuits which were clearly driven by wholesale projects.[17]

The second definition ("account for full cost and benefits of DER growth") should be used to evaluate any investments necessary for wholesale projects, or for projects ostensibly necessary to deploy DERs as an alternative to distribution capacity investments. These types of projects account for investments in 200 out of the 263 circuits in SCE's rate case.

[16] SWP, p. 29.
[17] A.16-09-001, Exh. TURN-06, p. 72-73. TURN did object to the full "automation" proposed by SCE based on finding less expensive technology solutions to meet the same goals.

An example of why upgrade costs must be considered in advance is illustrated by SCE's proposal to "modernize" about 74 circuits so that it can procure deferral projects. SCE forecasts the deferral benefit would be about $40 million, but the upgrade costs would be about $80 million.[18] On its face, such an investment does not make sense. However, if the full "upgrade" costs are not included in the net benefits analysis, they would become sunk costs and would never be visible in a net benefits analysis. Such a result would be entirely at odds with the goal of providing net benefits to ratepayers.

Any benefits not captured in the LNBA tool may be proposed by utilities but must be concrete, quantifiable, and flow to ratepayers. For example, if a utility plans to invest in technologies that allow DER's to bid in to wholesale market to provide frequency response, the utilities may quantify the value of this service if it is not incorporated in the LNBA tool.

Options for Assessing Net Benefits

The SWP appropriately finds that assessing net benefits is complex and may require a combination of approaches. TURN fully agrees, and suggests also that the approach for assessing "net benefits" may be different depending on the type of DER being addressed.

For continued installation of Rule 21 upgrades due to autonomous growth, Option 1 of assessing the cost effectiveness of individual technologies may be sufficient.

With respect to the four options presented, TURN seeks to balance theoretical best practice with practicality. Most existing rate case litigation essentially uses Option 1 to evaluate utility proposals. TURN believes that some combination of Options 2 and 4 offers the best ideal solution for calculating net benefits. Moreover, in the long run the application of the risk-

[18] A.16-09-001, Exh. TURN-06, p. 75-78.

informed prioritization process could obviate the need for individual benefit cost analysis. Ideally, the evaluation criteria and scoring methodologies developed for the risk-informed prioritization process will incorporate both benefit (economic, environmental, and reductions in risk) and cost considerations.

Additionally, in the long run the Commission could explore the potential to adopt some type of performance incentives for DER-related investments, as is presently being tested in the IDER pilots.

There is a classic incentive problem posed by grid modernization investments. Utilities may easily view these investments as an avenue to grow rate base and profits, regardless of whether they are necessary, cost-effective, or result in proportional benefits. The current construct is one where the reward for these investments flow to utilities, while the risks of over-investment or stranded costs fall on ratepayers.

While a strong requirement that utilities demonstrate net benefits may help somewhat in this regard, the utility can use optimistic assumptions regarding several parameters, such as forecast DER growth or avoided deferral costs, to drive higher benefits than will actually be realized. There should therefore be a mechanism *ex-post* to penalize utilities if benefits or key driving assumptions are not realized. Such a performance-based metric can, if implemented correctly, help align utility investment proposals with ratepayer benefits rather than financial incentives. For example, the Commission could institute the following performance-based metrics to align utility investments more squarely with ratepayer benefits:

- For investments whose benefit is derived from realization of DER growth scenarios, over-forecasting growth of certain technologies (based on actual versus forecast growth) should result in disallowance of utility return on equity (ROE) for related investments.

- For investments whose benefit relies on realization of certain revenues or even a specified increase in reliability, the utility must track and quantify the realization of these benefits. If they are not realized within a reasonable range of sensitivity for a specific year, the utility should not earn its ROE on that investment for a given year.

TURN has historically been skeptical of performance-based incentives, as our experience has shown that the huge information asymmetry between utilities and regulators makes it very difficult to calculate adequate benchmarks and penalty/reward ranges. However, such mechanisms could be considered if there are reasonable external benchmarks that could work better than utility investment forecasts. TURN hopes these broad outlines and recommendations will spur further stakeholder discussion on how the Commission can better align utility incentives with ratepayer interest and investments in technologies that are actually needed to integrate DERs and extract the most value at least cost.

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