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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.	R.14-10-003 (Filed October 2, 2014)

FINAL REPORT OF THE IDER WORKING GROUP FILED BY SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E), PACIFIC GAS AND ELECTRIC COMPANY (U 39 M), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND SOUTHERN CALIFORNIA GAS COMPANY (U 904-G)

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Dated: **May 31, 2016**

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Pursuant to the ruling of Administrative Law Judge Hymes dated February 29, 2016, Southern California Edison Company (SCE) files on behalf of the Integrated Distributed Energy Resources Working Group (IDER Working Group) the attached "Final Report of the IDER Working Group." This filing is made pursuant to a directive in the Ruling to SCE, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCal Gas).

Respectfully submitted,

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/s/ R. Olivia Samad

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DATE: May 31, 2016

Attachment A

Final Report of the Cost-effectiveness Working Group in Phase I of the Integrated Distributed Energy Resources [IDER | R. 14-10-003] Proceeding

Filed May 31, 2016

A. Background

The IDER Phase 1 Cost-effectiveness Working Group (CEWG) submits this final report to the CPUC pursuant to the October 9, 2015, Administrative Law Judge Ruling in Rulemaking 14-10-003, which states: "A working group is established in Rulemaking 14-10-003 with the objective of evolving the first phase of the Commission staff proposal into a consensus proposal for updating the Commission's cost-effectiveness (CE) framework."

A CEWG status report, *Working Group Recommendations for Inputs to the Avoided Cost Calculator of the Decision to Update Portions of the Commission's Current Cost-Effectiveness Framework*, was submitted by the IOUs on February 2, 2016. On February 29, 2016, an ALJ ruling[1] authorized the Working Group to continue to meet in order to complete its tasks. The Ruling directed that the Working Group should cooperatively develop a final consensus report to be filed no later than May 31, 2016.

B. Recommendations

In this report we make three specific recommendations, and report on the CEWG's discussion of various topics.

<u>Recommendation #1: Updating Discount Rate</u>
CEWG recommends that an order be issued in the IDER proceeding that informs all CPUC proceedings in which cost-effectiveness analysis is done that:

- All cost-effectiveness analysis should use the latest approved after-tax Weighted Average Cost of Capital (WACC) for each utility as the discount rate, which should be updated in all of the various cost-effectiveness reporting tools whenever available, at least until Phase 3 of this proceeding, when there will be further discussion about appropriate discount rates.
- Individual resource proceedings cannot change the discount rate used in their cost-effectiveness analysis for some or all programs, as has happened in the past.

In addition, the CEWG notes that although the discount rate is referenced in the DR Inputs tab of the avoided cost calculator, it not used within the avoided cost calculator, and should be deleted from Attachment 2 of *Working Group Recommendations for Inputs to the Avoided Cost Calculator of the Decision to Update Portions of the Commission's Current Cost-Effectiveness Framework*.

<u>Recommendation #2: Individual Program Avoided Costs</u>
The output of the avoided cost calculator provides avoided costs that reflect all costs related to traditional generation. This output is then used to determine the avoided costs of individual DERs,

[1] Administrative Law Judge's (ALJ's) Ruling Directing Comments to Be Filed on the February 2, 2016, Status Report of the Integrated Distributed Energy Resources Working Group, February 29, 2016.

based on load shapes and other metrics, which are *specific* to particular resources, technologies and programs. For example, load shapes, which estimate hourly energy savings are used for each EE measure, adjustment factors are used for DR programs, and energy generation profiles are used for renewables.

CEWG recommends that general guidelines be issued in the IDER proceeding that informs all CPUC proceedings in which cost-effectiveness analysis is done that:

The methods used to modify the output of the Avoided Cost Calculator to determine the avoided costs of specific technologies – whether end-use load shapes for energy efficiency, adjustment factors for demand response, generation profiles for customer generation program, or any other method – should be:

1. Transparent: The derivation of the method should be clear, and the steps of the process used to determine the avoided costs of any particular program or technology should be clearly defined and described.
2. Available: The method should be accessible by any party to a proceeding, and cost-effectiveness filings should provide clear links to this information.
3. Updated periodically: The methods should be updated as often as possible without incurring undue expense, and information about the currency of the method should be easily accessible.
4. Accuracy: Actual customer (or other) data should be used to develop these metrics, but computer simulation is often an acceptable alternative when data-based studies are too costly.

<u>Recommendation #3: Future Phases</u>
The CEWG recommends that the best approach for Phase 2 is to wait until the DRP proceeding further develops their methods for determining local values for DERs. The CEWG also agreed that it would be useful to develop a detailed list of Phase 3 issues, which could help determine the best process(es) to use for those issues. The CEWG does not make any recommendation as to the stakeholder process the Commission should follow in Phases 2 and 3.

The recommended list of Phase 3 issues follows. This list is a combination of topics discussed by the CEWG and topics added by Energy Division staff.

<u>Draft List of Phase 3 Issues</u>
The Energy Division staff proposal on IDER cost-effectiveness included topics 1-4 below. Since that time, as a result of discussion among Energy Division staff and/or the IDER Cost-effectiveness Working Group, topics 5, 6 and 7 have emerged as additional issues needing attention. Topics 1-4 have also been modified based on these discussions.

1. **Incorporate uncertainty**: Estimation of many costs and benefits associated with DERs is uncertain, and we may be providing decision-makers with a false sense of precision when we report cost-effectiveness results. Various techniques for better inclusion of the uncertainty in cost-effectiveness analysis have been proposed:

   - Include sensitivity analysis on key variables (possibly as an interim measure), as is currently done for demand response
   - Incorporate covariance analysis into some of our models
   - Explore probabilistic models, especially for avoided costs

2. **Align the cost-effectiveness framework with California's environmental goals**: California state policy clearly emphasizes the importance of decreasing GHG emissions and improving air quality. However, this has been incorporated into our cost-effectiveness analysis in only a limited way, in that we include an avoided GHG cost. Other non-energy impacts[2] (NEIs) are included in some of the cost-effectiveness tests used for some resources. There are several schools of thought about how to approach this issue, including:

   - Cost-effectiveness tests should be strictly financial, and NEIs should be considered externally to the cost-effectiveness framework, such as with the loading order or technology-specific incentive programs.
   - The existing cost-effectiveness tests should incorporate NEIs on an optional basis, where each resource proceeding determines if, when and how to consider NEIs. (This is the current practice.)
   - Adopt one of the methods currently used in a particular proceeding for use in all existing cost-effectiveness tests for all resources.
   - The existing cost-effectiveness tests should incorporate an established set of NEIs, which would be consistent across proceedings and technologies.
   - Establish a new societal cost-effectiveness test that includes values for climate change/GHG mitigation, environmental protection benefits, and possibly other NEIs, which would be consistent across proceedings and technologies.

   The question of which of the above options should be chosen is closely related and probably inseparable from the question of how the various cost-effectiveness tests (including a possible new societal test) should be used for program approval, design and evaluation, as well as possible cost sharing or mutual goal making with other agencies and organizations (see #5 below).

3. **Developing a common framework of costs and benefits**

   Each resource proceeding currently uses a somewhat different list of (or methods to determine) the costs and benefits used to calculate cost-effectiveness, or may be considering the addition of new inputs or methods.

   a. Existing costs and benefits: We will consider how to better coordinate the existing methods and inputs, which currently vary across proceedings. For example (not a complete list):

      - Administrative costs: The methods of allocating common administrative costs to the programs or measures, and the guidelines, for which costs must be included, are inconsistent.
      - Participant (non-equipment) costs: Participant transaction costs and value of service lost (which includes both productivity and comfort losses) are estimated for demand response, but not for other resources. It is possible that these costs should be considered to be (and treated as) non-energy impacts
      - Net to gross: This is a measure of "free-ridership," or the extent to which the existence of a ratepayer-funded program resulted in energy savings (as opposed to energy savings

[2] Non-energy impacts include social, utility and participant-related costs and benefits not directly or easily attributable to energy savings, such as reduction in air pollution, job creation or loss, change in the number of customer service requests to the utility, impact on property values, and increase in participant comfort.

that would have occurred anyway). It is used to decrement both costs and benefits of energy efficiency programs, but is not estimated or used for other resources

Should these costs and benefits (and related metrics) continue to be used only for the resources or technologies where they are particularly significant? Or, should all resources consider the entire list of costs and benefits, even if the value of some of them is likely to be zero?

b. Incorporating new costs and benefits: Several new costs and benefits are under consideration in one or more proceedings. For example (not a complete list):

- Renewable integration costs: The RPS and LTPP proceedings are examining the costs associated with integrating renewables into the grid. Because most renewable technologies are intermittent, operation of an electric grid with large amounts of renewables is considerably different than operation of the traditional grid. Different DERs can either increase or decrease these integration costs. For example, demand response and storage can be used to avoid renewable curtailment during hours of high solar and wind generation, thus decreasing a significant renewable integration cost.
- Value of flexible generation: In the demand response proceeding, the value of dispatchable, flexible generation has been extensively discussed, and a small adder has been adopted.
- Ratepayer interests: SB350 defines a set of "ratepayer interests," which are a set of non-traditional benefits that may accrue to ratepayers as the result of electric vehicle adoption. While some of these have been discussed elsewhere (e.g., energy-related GHG emissions), others have yet to be incorporated into the cost-effectiveness framework.

To what extent to these, and other emerging methods or inputs, overlap? Should these costs and benefits be used only in the proceedings where they are being developed? Or, should all resources consider these costs and benefits, even if the value of some of them is likely to be zero?

c. Including market and reliability impacts: Stakeholders have repeatedly remarked demand-side programs can supply additional, or different levels of, certain types of benefits which are not captured in our cost-effectiveness framework. These include the extent to which demand-side programs contribute to the reliability and resiliency of the grid, the ability for demand side resources to provide the flexibility needed to incorporate large amounts of intermittent generation, and market impacts of demand side technologies (e.g., energy price impacts, market transformation affects, mitigation of market power).

For the market and reliability impacts that can be quantified (if any), how should they be incorporated into the cost-effectiveness framework? Should they be treated as additional, optional benefits or costs which are added only when there is specific evidence that they exist? Should they be incorporated into the avoided cost calculator? How should we treat those market and reliability impacts that cannot be quantified?

d. A**lign the avoided cost concept with the needs of the grid and California's long-term goals**: We will consider whether the assumptions behind the current avoided cost calculator will continue to align with the state's environmental goals and the operational needs of the grid and, in particular, examine the feasibility and advisability of redefining the marginal unit used as the basis of most of the avoided costs. We will consider the impact of shifting emissions reduction responsibilities from the transportation sector to the electrical industry, and closely examine what, precisely, we are avoiding with demand-side resources within the context of California's energy policies, goals, and priorities. Questions that must be considered are:

Has the "avoided cost" concept outlived its usefulness? In other words, is it reasonable to assign value to DERs based on the generation it avoids? If so, is it reasonable to use this method for all DERs, including customer generation technologies which produce energy?

If we continue to use an avoided cost-based method, should the marginal unit of generation still be based on a gas turbine, or should it be based on a renewable or other generation technology. Or, should avoided costs be based on something else, such as a ton of carbon?

Another closely-related question is whether each utility's weighted average cost of capital (WACC) is the appropriate discount rate for some (or all) of the cost-effectiveness tests.

e. **Develop guidelines for the use of each Standard Practice Manual (SPM) test and a better understanding of the usefulness of each SPM perspective:** Energy Division staff have discussed the need to develop a policy rationale and recommendations for how the various SPM tests are used to determine the cost-effectiveness (and, often, budget approval) of DERs. Each SPM test, which are shown in Table 1, offers a different perspective (or combination of perspectives), yet we have never closely examined the rationale for preferring one perspective over another. Nor have we closely examined the value of each of these perspectives in helping us achieve state goals.

Table 1

Standard Practice Manual Tests			
Abbr.	**Name**	**Perspective**	**Description**
TRC	Total Resource Cost	Utility + Participant	Combines the costs and benefits of the program administrator (usually the utility) and the participants
PAC	Program Administrator Cost	Utility	Includes costs and benefits experienced by the program administrator (usually the utility)
RIM	Ratepayer Impact Measure	Impact on rates	Includes all PAC costs and benefits, plus changes in revenues
PT	Participant Test	Participant	Includes costs and benefits experienced by the participants
SCT	Social Cost Test*	Society	Includes all TRC costs and benefits, plus several environmental benefits and a lower discount rate

**Proposed by staff in 2013, but never adopted in California*

In recent years, within the arena of cost-effectiveness analysis (both within CPUC proceedings and in other jurisdictions), there has been much debate about two issues: 1) whether cost-effectiveness tests appropriately reflect environmental goals, and 2) whether cost-effectiveness tests appropriately reflect the relative significance of the utility and participant perspectives (i.e., the "TRC vs. PAC" debate). While the first issue will be considered as part of #2 above, we also need to consider the second issue, and in particular, under what circumstances the various tests should be used for budget approval, program design, and evaluation, as well as possible cost sharing or mutual goal making with other agencies and organizations. Among the various schools of thought on this are:

- Replace the TRC, which is currently considered the primary test of cost-effectiveness, with the PAC test.
- Replace the TRC with a societal test.
- Use cost-effectiveness tests that are strictly limited to financial costs and benefits, and use some other method of valuing NEIs.
- Use a variety of tests, depending on the objective (e.g., budget approval, procurement)

A related issue is: At what level of granularity should cost-effectiveness be measured? Should we measure cost-effectiveness at portfolio, program or measure level, and in what circumstances? What level of geographic granularity should we use?

To answer these questions, we also need to determine what the definition of various terms, such as “portfolio” and “program” are. We currently consider “portfolio” to refer to an entire package of resource-specific programs continued in one budget application, but a “portfolio” of DERs could also be a set of bundled resources (group of different technologies) designed to meet a local, or other specific grid need. Therefore, “portfolio” could be large or small. One suggestion that is supported by some stakeholders is to use define a portfolio for any given need, and then use portfolio analysis for budget approval and program analysis for program design purposes.

f. **DER Integration**: Bundles of different technologies, as well as new technologies, are likely to become more and more important as we develop new procurement methods and markets. Hence, there is a need to enable valuation of bundled and emerging technologies that don’t fit into the current technology-specific cost-effectiveness framework. How can we better measure the benefits of bundled technologies, given that certain things are measured differently for different technologies? Are those differences necessary, and if so, how do we attribute the energy and capacity savings to the different technologies? If not, how do we develop a universal method? How do we account for interactive affects (e.g., installing a more efficient HVAC system improves energy efficiency but decreases the amount of available demand response)?

Possibly the most significant difference between the various resource proceedings is in the second step of the cost-effectiveness process, which is using the output of the avoided cost calculator output to determine individual program/measure avoided costs. (EE uses measure-specific load shapes, DR uses adjustment factors, and DG use energy generation curves.) If we can develop a universal method for this part of the cost-effectiveness process (or develop a mechanism to combine the existing methods) how do we determine the avoided costs of bundled technologies without double-counting? If we cannot develop a universal method, can we narrow this step down to two methods – one for dispatchable resources, and one for non-dispatchable resources?

How does this issue impact emerging technologies, such as storage and electric vehicles, and how does it feed into integrated resource planning?

How can we create a universal reporting tool so that we can compare different technologies and estimate cost-effectiveness of bundled technologies? Consistency of reporting tools across resources is highly desirable, because it will be difficult to measure the cost-effectiveness of bundled resources without a consistent reporting tool.

Frequency of reporting should be more uniform across resources. (Currently, EE cost-effectiveness is reported annually; DR and ESA only when application or advice letter is submitted, DG only when evaluation is done.) How can we move to a unified reporting timeline, which includes technologies (e.g., EVs) whose cost-effectiveness framework is emerging?

g. Additional Avoided Cost Calculator Updates

Based on feedback from the CEWG and other stakeholders, Energy Division made the following recommendations to E3, the consultant currently performing the update of the Avoided Cost Calculator. The 2016 calculator update will reflect these recommendations.

- Base the hourly allocation of avoided generation capacity on the unserved energy output generated by the RECAP model.
- Continuing to model avoided energy costs on historical data is in error and must be corrected.
- Adopt the method currently used in the RPS calculator for determining the hourly energy price shape and market prices.
- Adding renewable curtailment to the avoided RPS cost is out of scope and should not be implemented at this time.

Some of these recommendations will require future refinement or discussion, and we anticipate that more issues will emerge in the future related to the details of the models and methods contained within the avoided cost calculator, and will require additional stakeholder input.

Appendices:

A. March 18, 2016 Meeting Summary
B. March 29, 2016 Select Meeting Notes
C. April 18, 2016 Meeting Summary and Notes
D. May 16, 2016 Meeting Summary

Appendix A

Cost Effectiveness Working Group (CEWG) Meeting in Accordance with Integrated Distributed Energy Resources Proceeding [IDER | R.14-10-003]

Tuesday, March 22, 2016 from 9:00 to 10:00 AM

<u>Conference Call Meeting Notes</u>

- ACC version control: Group is in agreement that it will wait until ACC is updated, then will name it.
- Data inputs: ALJ Hymes will issue a decision on topics in Status Report prior to CEWG's issuance of Final Report. She does not intend to wait for Final Report, will write decision based on what is currently on the record (Status Report + comments on Ruling). Items to be addressed in ruling can continue being discussed – further recommendations can be field in next report, no guarantee it will affect the ruling in mid-April. Parties can weigh in the ruling thereafter.

1. Review of spreadsheet (last page below) of CEWG Issues ALJ asked us to consider.
    a. Thorough job in how we can do version control. One comment on indicating changes. Other than that, there's no discussion. Hence, let's wait until we update calculator and give it a name, then participants can comment. Nothing to discuss on version control. Group is in agreement.
    b. Data Inputs. ALJ asked for comments on most of the issues in Status Report. Idea was to get something on the record. ALJ intends to do a decision sooner rather than later (not clear exactly when). Does not intend to wait until next status report; she wants to write decision w/what is currently on the record (status report and comments on ruling). Items you would address in ruling can continue discussing and put further recommendations in next report, but no guarantee it will affect ruling. ALJ may decide to make decision without those recommendations. Does not mean it can't change – group can weigh in on future decision.
        1.) Which data should we update? Appendix is correct, per group. Any other items related to this we need to discuss?
            a. [Callahan-Dudley, MCE]: Would like to have discussion on using carbon metric across all resources, including societal cost of carbon.
               [Morgenstern, CPUC]: This is out of scope. There were comments on additional avoided costs that should be added to the CE framework and calculator, but changes to framework of ACC itself are phase three issues, hence should be put there. ALJ and ACO will most likely not make a decision on these items until then. Issues we are assigned to address are ***existing*** data inputs. GHG items are Phase 3 issue.
            b. [?]: SB 350 OIR: GHG emission accounting for preliminary scoping of issue that uses social cost of carbon. This is to be considered in the proceeding.
2. Process, Timing, Funding – All these were well addressed in comments.
   [White, Clean Coalition]: When update should occur -- is there any value in following to arrive at near consensus?
   [Morgenstern, CPUC]: Two parties recommended update should occur every two years, one party every year. Unless someone has anything new to this discussion or change their minds, we will have to leave it up to ALJ.

3. Time Allocation of Capacity. Agreed it should be uniform across resources, considered part of calculator, was separate process in past. Only IOUs addressed which model to use. Not sure if there's enough on record to determine how to move forward on this issue.
   [Gavelis, PG&E]: There were some comments, what else are we looking for?
   [Morgenstern, CPUC]: There were comments, but perhaps not enough for ALJ to determine whether one method over another. IOUs agreed on adopting RECAP. May want to use other methods if they want to adopt local capacity.
   [Barkovich, CLECA]: Vetted RECAP for DR, but don't know enough about using ELTC.
   [Morgenstern, CPUC]: Discussing further will not get us anywhere.
4. **Resource Balance Year: General agreement about process. Huge policy debate: Should we reset RBY to current year, hence getting rid of short term costs? Parties provided great comments, arguing pros and cons. Hope that this will help the Commission in making a decision. Is there any value in continuing this to offer recommendations? [CEWG Group Answer: No.]**
5. Load Shapes Allocation Factor. Resource load shapes: Up to individual resources, not a huge priority.
   [Woychik, Strategy Integrations]: PG&E's work on load shapes is critical, was mentioned in comments. Not sure what we need or can do right now, but important – we either get poor averages or specific data.
   [Morgenstern, CPUC]: Question is whether we should use specific guidelines. Should IDER have general guidelines for generation shapes, adjustment factors for individual resources? Do we have ability to develop the guidelines for this process?
   [Christ-Janer]: Slides available?
   [Woychik, Strategy Integrations]: No, but everyone is moving to use AMI data for everything. Do we need guideline for this? Or so we just use data?
   [Christ-Janer]: Agrees w/Woychik.
   [Morgenstern, CPUC]: Further discussion needed, group should develop general guidelines, even if it's coming up w/better load shapes using the data available (since we have more data).
   [Hawiger, TURN]: Not clear how load shapes for demand of individual customers that vary w/time play into CE allocation of particular resources that are laid over on top of load shapes.
   [Morgenstern, CPUC]: Customer load shapes are used in avoided costs in aggregate, part of CE process, determining actual savings or generation of the technology.
   [Gavelis, PG&E]: Cataloguing of how we determine load shapes.
   [Morgenstern, CPUC]: Should start by doing cataloguing, need to further discuss with goal of providing more recommendations to Commission.
6. CE other than avoided costs. No reason it can't be uniform across resources, although for some resources they will be zero. Missing: No definitive list of what these are, and this will be useful to make such a list to discuss individual items on the list. Useful for Commission to have. Otherwise, ALJ will simply generically say, "CEWG wants values to be uniform," which is too vague.
   [Barkovich, CLECA]: Comments and reply comments did state that we need further discussion on this.
   [Morgenstern, CPUC]: We then should make a list.
7. Social Cost Test: Is it an easy enough issue that we can agree whether we should have one or not? Or should we defer to Phase 3? Sentiment was that we need more discussion and hence should defer to Phase 3. Some parties commented that it depends on how this test will be used. Not a feeling on whether we should reach a consensus now.
   [Woychik, Strategy Integrations]: Societal Test was to use GHG adder.
   [Barkovich, CLECA]: Tricky to find societal cost of carbon.

[Binz]: Contentious. PG&E and CEWG raised issue that when you look at GHG only looks at entire lifecycle of resource.
[Christ-Janer]: Understandable to not address in detail until Phase 3, but needs to be kept in mind as it's a huge issue that makes a substantial difference.
[Morgenstern, CPUC]: Consensus is to defer to Phase 3, but continue discussing, w/ understanding that we state, "Here's what we think about it."
[?, SCE]: What should we deprioritize for report due May 31, not sure if we should get this in the report. Woychik: In agreement that we can't address now, but can be deferred to Phase 3.
[Morgenstern, CPUC]: Everyone in agreement. Discussion to be deferred to Phase 3.

8. Portfolio Program Analysis. May depend on need of particular proceeding. Unresolved issue. Do we want further recommendations on this
[White, Clean Coalition]: Not discussed exhaustively.
[Morgenstern, CPUC]: Hence, we should take a stab.
[Hawiger, TURN]: Woychik's point on demand profiles can be a part of this discussion. Perhaps we can add this – how is CE used? Raises issue of are you using CE for broad evaluation of portfolio or for procurement of individual programs? How granular?
[Morgenstern, CPUC]: How granular we want to go is important, but we're not using the data we have because we're not sure how to use it and what's appropriate. Hence, this discussion could be useful.
[Christ-Janer]: Agrees that this needs more discussion.
[Morgenstern, CPUC]: More than the portfolio program discussion. It's about granularity and how we apply data. Hence, we should add this.
9. Reporting Tools: May or may not be a big priority. Question of do we want to develop guidelines? Are reporting tools accessible? We should take further stab on discussing this (E3 CE Calculator used for EE; DR reporting spreadsheet.) Other proceedings (including ESA) have no standard tools – whatever consultant puts in report.
10. Funding for Future Phases: Adequately addressed in comments. Any further discussion? [CEWG Answer: No.]
11. Process for May 31 Report. Not tremendous amount of items that need to be discussed. We could have a couple of meetings and be done. Nothing keeps us from submitting a report earlier than May 31, which potentially means an earlier decision.
[Nickerman, PG&E]: Would like timing of this decision.
[Morgenstern, CPUC]: Will find out timing from ALJ. If we get done early and issue in April, could she consider in upcoming decision?
12. How many meetings? Next one is March 29 from 1:00 to 4:00 PM. Given that we may not have room, CEWG should assume that this may occur by conference call.
    a. Given current spreadsheet: How many meetings, timeframe for each? [CEWG Answer: Two meetings would be enough.]
    [Morgenstern, CPUC]: Four topics: Load shape question; what C and B costs are that should be considered across resources; portfolio and program, granularity of data; reporting tools.
    [White, Clean Coalition]: There may be individual topics that come up that warrant additional meetings before final meeting, but in agreement.
    b. Next meeting topic: Granularity of data or load shape as topics? Easier items first or harder topics?
    [Woychik, Strategy Integrations]: Question for PG&E: Would they be willing to discuss work on load shapes?
    [Nickerman, PG&E]: Specifically what on load shapes?

[White, Clean Coalition]: More complex items should be addressed over the course over two meetings rather than just one at the end. Hence, address everything in first meeting, so that any other more complex items can be covered in another meeting.

c. Joy Morgenstern will work on agenda for March 29 meeting. Any suggestions should be sent to Joy. She will send out proposed agenda by end of this week, everyone should weigh in, and then final agenda will go out before meeting.

Partial List of Attendees/Participants

Paula Gruendling, California Public Utilities Commission (CPUC)
Natalie Guishar, CPUC
Joy Morgenstern, CPUC
Stephanie Wang, Center for Sustainable Energy (CSE)
Sahm White, Clean Coalition
Barbara Barkovich, California Large Energy Consumers Association (CLECA)
Jennifer Chamberlin, Johnson Controls
Michael Callahan-Dudley, Marin Clean Energy (MCE)
Eric Woychik, Strategy Integrations
Sasha Cole, Office of Ratepayer Advocates (ORA)
Eric Lee, Southern California Edison (SCE)
Marcel Hawiger, The Utility Reform Network (TURN)
Joe McCawley (SDG&E)
Kevin McKinley, San Diego Gas and Electric (SDG&E)
Ron Binz, Consultant (PG&E)
Bill Gavelis, Pacific Gas and Electric (PG&E)
Luke Nickerman, PG&E
Karey Christ-Janer, Independent Consultant
Jaclyn Harr, SolarCity

#	Issue (from 10/9 ruling)	Status Report	Discussed in 2/29 ruling	Status?	New issues from comments	To be discussed
1	Avoided Cost Calculator (ACC) Version Control	Described new system	OK	Done	use version numbering which highlights changes	Nothing
2	ACC data updates			Addressed in comments		
2a	Which data?	listed in Appendix B	Is Appendix B correct? How should list be updated?	"	update list of inputs annually as needed; no change to list of inputs w/out Decision	
2b	Update all data?	Yes or use threshold	All data or not?	"		
2c	Process	Resolution, like MPR	OK	"	Process for adding other inputs or huge data changes; model changes?	
2d	Timing	Annual or biennial	How often?	"		
2e	Funding	EE for first year	OK? Continue? Other source/ account? How much?	"	IDSM; EE/DR/solar/SGIP shared; no new balancing accounts	
3	Time allocation of capacity	listed options	Preference?	"	RECAP for now?, other methods for local	
4	RBY				Use alternate methods, possibly just for DR; allow different RBYs for flexible or local capacity; more review of capacity curve	
4a	From where?	LTTP	OK	Done	make adjustments after based on policy priorities or concerns	
4b	How determined?	Remove uncommitted DERs	OK	Done	may conflict with loading order	
4c	RBY=current year?	Discussed, disagreement	Preference? Impact on DR?	Addressed in comments	Need to address local / flexible capacity as well as system; Do lifecycle analysis, other adjustments, for DR	
5	Load shapes/allocation factors	Unclear	Describe guidelines	Addressed in comments	should be left to resource proceedings	
6	costs and benefits other than avoided costs	consistency across resources even if = zero	Zero values ok? Which inputs?	Addressed in comments		still no definitive list
7a	Develop Social Cost Test?	Discussed, disagreement, options listed	not mentioned	Unresolved		
7b	Social Cost Test timing	not addressed	not mentioned	Unresolved		Defer to Phase 3?
8	Portfolio/Program	Discussed, depends on need	not mentioned	Unresolved		
9	Reporting Tools	Needs further discussion	not mentioned	Unresolved		
10	Funding for future phases?	NA	Comments?	Addressed in comments		
11	Process for May 31 report	NA	NA	NA	NA	

Appendix B

Phase 1 Cost Effectiveness Working Group [CEWG] in the Integrated Distributed Energy Resources [IDER | R 14-10-003] Proceeding

March 29, 2016 | Golden Gate Room, CPUC

Energy Division Select, Limited Notes

A. Load Shapes and Adjustment Factors

1. Resource Load Profiles, CAISO Market Profiles

[Woychik]: Most important is AMI-based profiles. Individual customer AMI-based customer load profile.

[Morgenstern, CPUC]: Lots of work in EE on load shapes. There needs to be more research on this, but CEWG's consensus is that that is a resource-specific issue to be dealt with in EE. But do we want guidelines that cut across proceedings, recognizing that developing a load profile for EE technology is different from generation profile for DR program? Is there a guideline or do we want the individual proceedings to figure out?

[Woychik, Strategy Integrations]: Individual customer profile is the most important thing, especially for DR and EE, DG. It's the basis for the load forecast, load shifts that occur, aggregating up to a better load forecast, basis for locational load forecast and all DERs. It's a fundamental building block. The problem is we keep averaging those, versus using granularity at the customer level.

[Callahan-Dudley, MCE]: In addition to customer load profiles, there are various levels of granularity of load profiles. Starting from now to different LSEs. We already do avoided cost for each customer except for California.

[Woychik, Strategy Integrations]: System-level avoided costs and locational (distribution, circuit). When we talk about avoided costs. We need a load shape to define CE to determine when something is cheaper. When you are asking about CE, are we talking about aggregating all AMIs up to the system level?

[Morgenstern, CPUC]: Load shapes are technology-specific (lighting, AC, solar panels, etc.)

[Woychik, Strategy Integrations]: Those are not load shapes, but supply shapes. Load shapes are actually load.

[Morgenstern, CPUC]: That's what we call them. System-level avoided costs. The load that technology-specific adjustments we make to determine the CE of a particular technology. (EE: "load shapes", DR: "adjustment factors"). Questions:

a. Guidance we provide on load shapes to individual resource types
b. What's the granularity
   [Barkovich, CLECA]: Are we talking about the 8760 hours in the avoided cost calculator?

[Morgenstern, CPUC]: Yes. We did a similar measure across resources. The only question is, "Are there general guidelines about that process that we feel are inconsistent? Is there any guidance we want to give the individual resource proceedings about this process?" This is the only question on the table.

[Nickerman, PG&E]: EE is standardized. But let's talk about DR's adjustment factors, which are not used in EE. What type of guidance are we looking to provide in determining these factors?

[Morgenstern, CPUC]: Is there something lacking in that process right now?

[Helgens, PG&E]: Guidance on how to use or form the load shapes. Structural load shapes should be forward looking rather than historical-looking. PG&E is suggesting this, but not for all resources. This is a preference. (EE's load shapes come from the DEER database, so how would you do it on a forward-looking level?) Ideally you have an end-use metering study that tracks where end use is taking place as a basis. HVAC has a lot of metering. Based on your sample you can estimate what the average load shape would look like. You can weather-normalize it or add weather so you can determine when that HVAC system will peak. Hence, you can determine seasonal and day shapes. Then if you are metering over a long period of time you can also get 8760 to match. You can determine "Is it contributing to peak, is it on peak or off peak?"

H. Attendees (in person and phone):

Karey Christ-Janer, Independent Consultant
Brian McCullough, California Energy Commission (CEC)
Kellie Smith, California Energy Efficiency Industry Council (CEEIC)
Barbara Barkovich, California Large Energy Consumers Association (CLECA)
Stephanie Wang, Center for Sustainable Energy
Sahm White, Clean Coalition
Nathan Barcic, California Public Utilities Commission (CPUC)
Paula Gruendling, CPUC
Natalie Guishar, CPUC
Joy Morgenstern, CPUC
Carmelita Miller, Greenlining Institute
Michael Callahan-Dudley, Marin Clean Energy (MCE)
Merrian Borgeson, Natural Resources Defense Council (NRDC)
Bill Gavelis, Pacific Gas and Electric (PG&E)
Ron Helgens, PG&E
Luke Nickerman, PG&E
Dan Buch, Office of Ratepayer Advocates (ORA)
Maya Alunkal, Southern California Edison (SCE)
Dan Harper, SCE
Devin Rauss, SCE
Athena Besa, San Diego Gas and Electric (SDG&E)
Joe McCawley, SDG&E
Sara Gersen, Sierra Club
Mike Nguyen, Southern California Regional Energy Network (SoCalREN)
Brian Warshay, Solar City
Eric Woychik, Strategy Integrations
Eric Borden, The Utility Reform Network (TURN)

Other Information:
For procedural details relating to the Integrated Distributed Energy Resources [IDER] proceeding [R. 14-10-003], commenting and the record development process, and the role of this working group meeting within the proceeding, please refer to the "Administrative Law Judge's Ruling Directing Comments to be Filed on February 2, 2016 Status Report of the Integrated Distributed Energy Resources Working Group," issued on February 29, 2016.

The contact person regarding the Commission's cost-effectiveness evaluation method is Joy Morgenstern, Senior Regulatory Analyst in the Demand Response Section of the Energy Division. She can be reached at joy.morgenstern@cpuc.ca.gov or at 415-703-1900.

The contact person regarding the proceeding is Natalie Guishar, Regulatory Analyst in the Demand Response Section of the Commission's Energy Division. She can be reached at natalie.guishar@cpu.ca.gov or at 415-703-5324.

Appendix C

Phase 1 Cost Effectiveness Working Group [CEWG] in the Integrated Distributed Energy Resources [IDER | R 14-10-003] Proceeding

Monday, April 18, 2016 | Golden Gate Room, CPUC

Energy Division Summary and Notes of April 18, 2016 CEWG Meeting

Avoided Cost Calculator (ACC) Update

We discussed the calculator update process, which is underway. E3 is performing the update and would like to meet with the CEWG to discuss the details (e.g., how to calculate avoided energy and the renewable premium, feedback on version control). We will require one or two meetings in May/June. The first will be in mid-May and N. Guishar will set it up. The ACC update is scheduled to be completed by July 1.

Discussion of Previous Meeting Summary

Topic #2: Costs and Benefits Other Than Avoided Costs. PG&E objects to the inclusion of "market & reliability impacts" in this category. They question whether this will actually make the cost-effectiveness framework more consistent across resources, and believe that instead it could make the framework *less* consistent. They also believe that market and reliability impacts may more properly be placed *within* the avoided cost calculator. The meeting summary will be edited to reflect PG&E's objection.

Topic #3: Portfolio/Program Analysis. The definitions of "portfolio" and "program" are unclear. A "portfolio" of DERs could be bundled resources (a group of different technologies) designed to meet a local, or other specific grid need. Therefore, "portfolio" could be large or small. Some members feel that portfolio analysis should always be used for budget approval and that program analysis is more appropriate for program design purposes. Energy Division (ED) recommends more discussion of this issue during Phase 3, when we discuss how to use cost-effectiveness results.

Cost-Effectiveness Reporting Tools

CEWG members agreed that:

- Consistency of reporting tools across resources is desirable. It will be difficult to measure the cost-effectiveness of bundled resources without a consistent reporting tool.
- Frequency of reporting should be more uniform across resources. (Currently, EE cost-effectiveness is updated annually. DR and ESA cost-effectiveness is only updated when an application or an advice letter is submitted. DG cost-effectiveness is only updated when evaluation is done.) We need to move to a unified reporting timeline, which should include technologies (e.g., EVs) whose cost-effectiveness framework is emerging.
- The CPUC should make development of a common cost-effectiveness reporting tool and timeline a priority in Phase 3.

Updating Discount Rate

CEWG members agreed that:

- All cost-effectiveness analysis should use the latest approved WACC for each utility as the discount rate, which should be updated in the various cost-effectiveness reporting tools whenever available, at least until Phase 3, when there will be further discussion about appropriate discount rates.
- The Commission should make it clear that resource proceedings cannot change the discount rate used in their cost-effectiveness analysis for some or all programs, as has happened in the past.
- The discount rate is not used within the avoided cost calculator, and should be deleted from Appendix B.

Process for CEWG Final Report
Energy Division will continue to provide meeting summaries. ***However, the completion of the Final Report due May 31 awaits a volunteer.***

Sensitivity Analysis
Sensitivity analysis is performed for DR programs on specific variables that are likely to have a significant impact on cost-effectiveness results. The sensitivity analysis is embedded in the cost-effectiveness reporting tool and would require no additional work for the IOUs or program administrators. It is possible that this could be used for resources *other* than DR. This would be a short-term substitute until we could adopt a more sophisticated way of incorporating uncertainty into our cost-effectiveness models. However, the CEWG consensus is that it would be costly and difficult to adopt this in the short-term, and prefers to defer this to the Phase 3 discussion on uncertainty.

Load Shapes
The CEWG continued its ongoing discussion of the use of load shapes in the cost-effectiveness framework. The discussion did not result in any consensus. More discussion of this will occur in Phase 3.

Future Phases
ED solicited comments from CEWG members on the process the Commission should use to accomplish Phases 2 and 3 goals. ORA suggested that working group consensus could be difficult to obtain, so it might be better to use other mechanisms. Several members suggested that the best approach for Phase 2 is to wait until the DRP proceeding further develops their methods for determining local values for DERs. ***The CEWG agreed that it would be useful to develop a detailed list of Phase 3 issues,*** which could help determine the best process(es) to use for those issues. ***Energy Division asks CEWG members to submit lists of Phase 3 issues by COB on May 6, 2016.***

Meeting Highlights and Details.

1. Target completion date for Avoided Cost Calculator (ACC) update is July 1. Changes to calculator itself is a Phase 3 issue.
2. No consensus on Topic 3 (Portfolio/Program Analysis), hence will defer to Phase 3. [Parties identifying that further discussion is necessary: NRDC | Parties identifying that "Portfolio/Program" is understood to have a particular meaning: IOUs, CPUC, SoCalREN.] {Sierra Club: Does not believe further discussion of this topic is necessary in the working group, regardless of whether there is consensus on when portfolio vs. program-level analysis is appropriate.]

3. On Cost Effectiveness Reporting Tools, group reached consensus that there is a consistency issue. We can state this in the final report and ask that the Commission determine this in Phase 3. [Parties identifying issue with consistency: CPUC, TURN]
4. There is no short-term solution in lieu of sensitivity analysis right now, hence consensus is to address a more developed approach in Phase 3. [Parties identifying that sensitivity analysis should be addressed: CPUC, Strategy Integrations, SoCalREN, Clean Coalition]
5. Our job is to make changes to the CE framework, not to make changes to how the resources are procured. [Parties in agreement: CPUC, ORA, IOUs]
6. CEWG should come up with more discrete list of Phase 3 issues. CEWG participants: Please forward your list to Natalie Guishar by April 25, 2016.
7. Next meeting will be in mid-May and ED will send invitations. Topic will be E3's ACC update.

   A. Discussion of Previous Meeting Summary, Cost Effectiveness Reporting Tools.
      1. Continuing relationship between WG and E3 as ACC update proceeds.

      2. Appendix B (spreadsheet w/data inputs) – a few things should be discussed, in particular how we calculate avoided energy and renewable premium. Comments on how E3 makes changes in terms of version control, transparency, operators' manual, etc. We should set-up plan for a few meetings (2 perhaps) on the calculator in mid-May and June. Target completion date for ACC on July 1. Changes to calculator itself are a Phase 3 issue.

      3. Meeting Summary from March 29.
         [Borgeson, NRDC | Gersen, Sierra Club]: Topic 3. General agreement that portfolio level analysis should be used to determine whether DERs meet cost-effectiveness thresholds, if applicable. PAs would not be judged below the portfolio-level analysis. Purpose of this proceeding is to move to portfolios of different types of DERs. Hence using portfolio-level analysis is appropriate method of measuring DERs.
         [Busch, ORA]: Level of CE analysis depends on the question. Portfolio-level questions are not given priority necessarily. Not paramount going forward.
         [Woychik, Strategy Integrations]: Sounds like location first, then portfolio second.
         [Christ-Janer]: Portfolio can be seen as a micro- or macro. Traditionally we've seen it programmatically. But portfolio can be seen as bundled resources. Groupings or collections of DERs and their CEs have to be reevaluated at some point.
         [White, CC]: We need to evaluate the portfolio, actual physical resources before we can see how it relates to a program based on the resources actually deployed. Regardless of whether micro or macro, we need to look at the actual resources. Standard default methodology to look at what market value impact would be. We should aim to recommend a starting point, so am in agreement with proposal.
         [Helgens, PG&E]: Does market benefit mean reduction in price due to DER or net reduction in price?
         [Kandel, CEC]: Value of demand suppression – could this be estimated? Loss of producers supply could become a ratepayer benefit.
         [Morgenstern, CPUC]: In DR, participants can add market reliability to CE. The thought is that we can put this as a placeholder for other resources, primarily EE. Idea is we can add this to the framework. We don't have individual methods to measure – there may be market and reliability benefits that one party has access to research or beliefs they exist. It could be any kind of cost or benefit. For example, if there is research indicating that EE has

an additional benefit that should be changed in ACC because of the impact EE has on the market, so we should consider the additional cost and benefit. Hence, it's not a definitive list, but we can have a placeholder for anything that is well-documented and can be added later (current placeholder can be zero). Gives parties opportunity to add to the analysis, not an assurance that they can. Will note that PG&E objects to inclusion of market and reliability benefits in this category. Will defer to Phase 3. **Since not a lot of consensus, will revise to state, "Some parties believe…." Defer to Phase 3**
[Nickerman, PG&E]: Topic 2: Are we deferring market and reliability impacts deferring to Phase 3?

B. Cost Effectiveness Reporting Tools.
   1. Do we want to make them more uniform across resources? EE CE, new SQL calculator for EE and IOUs required to input data into this.
      [Borgeson, NRDC | Morgenstern, CPUC]: Frequency of CE reporting should be uniform across resources. EE, DR and Low-Income EE reporting every three years. (DR only when there is an AL or application.) DG only periodically when there is an evaluation. EE is also done annually for results.
      [Nguyen, SoCalREN]: Move towards a unified reporting timeline, common timeframe where long term procurement is framework that drives the timelines because EE has own scheduled not in synch with DR. Eventually we move towards a framework where have one procedure (universal timeframe)
      [McCawley, SCE]: If some solutions are multi-DER, then how do we report something that is DR-storage combination? If solicitations are market-based, this will also be applicable (such as DR).
      [Nguyen, SoCalREN]: Move uniform timeframe towards uniform methodology
      [Morgenstern, CPUC]: For DG resources (SGIP, NEM), they only have to report after the fact whether or not it's CE. DR does not do after-the-fact calculation. EE has an ex-ante evaluation. Going forward we have other technologies that will need to adopt something (EVs, etc.) **Group reached consensus that this is a consistency issue. We can state this in the final report, state that we want the Commission to determine this in Phase 3**.

C. Updating Discount Rate.
   1. This only happens every two or three years. E3 uses CEC's 20-year cash flow analysis. Hence WECC is not used in ACC, but used in the CE tool. Hence discount rate is separate from the ACC.
      [Morgenstern, CPUC]: In agreement that discount rate is what it is in the WECC proceeding, we don't change it, is everyone in agreement that we want this to be used across proceedings. Supports consistent use across proceedings.
      [Woychik, SI | Gersen, Sierra Club] agrees with consistency but would support use of societal discount rate.

D. CEWG Final Report Process.
   [Morgenstern, CPUC]: Morgenstern will do a meeting summary for today. Decision will be issued before Final Report (which is due May 31). She will produce decision right away because of the need to get ACC before July 1. Her decision will primarily approve the ACC. Fundamental changes to the ACC is a Phase 3 issue.

E. Sensitivity Analysis.

1. What is inconsistent in our proceedings? In DR we perform sensitivity along six variables. Not as great as using stochastic, probabilistic methods, but it's the best we currently have. Is the sensitivity analysis of the type done in DR useful in indicating that there is this level of uncertainty we should consider? Or should we talk in Phase 3. Hence, question is, "Is this a good idea?"

   [Barcic, CPUC]: It appears to be the next best option to doing stochastic. In DR: A Factor on availability, avoided capacity costs, load impact, specific variables most significant for DR.
   [Gersen, Sierra Club]: Sensitivity analysis for gas and carbon prices would be useful for all proceedings, and would not require a lot of extra effort. Sierra Club recommends using high- and low-end forecasts for natural gas and carbon prices to perform the sensitivity analysis, rather than adjusting these variables upward and downward by the same arbitrary percentage. This methodology is more useful than the sensitivity analysis currently conducted in the DR proceeding because the difference between the median- and high-end forecasts for these variables is bigger than the difference between the median- and low-end forecasts.

   [Nguyen, SoCalREN]: Would all resource providers have to conduct their own Sensitivity Analysis?
   [Morgenstern, CPUC]: IOUs would not have to do anything, just input their values. Just analysis that allows IOUs to move the lever up or down. No work required on the part of the IOUs, PAs, or parties. SA in DR protocols was primarily a guess.
   [Borgeson, NRDC]: Can also use sensitivity analysis to determine which variable matters most and help us direct efforts in Phase 3.
   [Morgenstern, CPUC]: Embedded in reporting tool E3 created. IOUs only have to input their values. If each of the six variables were 30% higher or lower, what would the TRC be? DR has no strict requirements unlike EE for CE (not required to be 1.0), hence just for informational purposes. *Everyone is in agreement that this needs to be done, but needs more discussion.* Sensitivity analysis is only offered as a temporary solution to other models that in the future. It's a substitute as a way to account for uncertainty. Question to ask is whether it would add to consistency or inconsistency? Would it add to much effort and time, taking away from the more important question of changing our models to better incorporate uncertainty?
   [Woychik, SI]: Covariance adds to the probabilistic nature and can be done easily. Package combinations using carefully crafted scenarios. Considering the resources required, we can use it as an alternative to a probabilistic model. Using covariance analysis would be simpler, but no one is willing to take it up, so we always go back to the lowest common denominator in CE. Read DR settlement on this covariance modeling: It adds probabilistic analysis around key variables. Adding covariance is easy and can be used in Phase 3.
   [Barkovich, CLECA]: ELCC modeling in RA has not produced reliable results yet, so I'm not sure how probabilistic modeling will change anything.
   [Buch, ORA]: In absence of actual basis of analysis, we should not indicate to other proceedings it should be used in the meantime, as it would be misleading. A more rigorous method should be discussed, but in the absence of an actual method to analyze, we shouldn't recommend other resources to use "something" without a point estimate.

[Morgenstern, CPUC]: Sensitivity and probabilistic analysis is where we want to go, but there is no simple way to change CE that would across resources currently. Uncertainty will be keyed up for Phase 3. (**Is there a short-term solution to add sensitivity analysis right now? Consensus seems to be, "No." We can reach a more developed approach then.**)

F. Further Discussion on Load Shapes.
[B. Horii, E3]: Measure shapes the way we measure the energy savings of different technologies. The amount of energy a refrigerator saves is not the same as an LED light saves. Hence, what is the avoided cost of a lighting measure vs. a refrigeration measure? We assume it's the demand savings so we can measure both the energy and capacity savings. This comes from DEER database, not end-use studies. Also, TOU shapes used in EE calculator, so IOUs have end-use data. Push is by ED for IOU to use hourly shape base and only use the TOUs when there's no fit with the hourlies. DR uses no load shapes – uses adjustment factors that are percentages, not load shapes. Uses combination of ELCC and loss of load probabilities. Not hourly, pre-baked shape analysis, but based on how you can operate the DR program.
[Woychik | SI]: Currently uses use and end-use modeling system. Just averages, not using AMI data. Using AMI and calculate and see changes that occur going forward, then you would have actual data. You could see actual peak change, rather than average change. You use actual peak data, rather than averages. You target high users with DR and EE. Using actual AMI data would be more accurate than using projected load shapes from DEER that acts as proxy. It would allow us to use aggregated line-segment data on temporal and geographic level. DEER is Excel-based and would not contain all the data we need.
[Alunkal, SCE]: Granular data is fine, but it's a cost issue. Question is does it make sense from a cost perspective to use AMI if the current data available will suffice?
[Christ-Janer]: We can state that the guideline is to use the most granular (if AMI, then so be it) as data.
[Morgenstern, CPUC]: How can we better determine program impacts and how do we better design programs? **Our job is to make changes to the CE framework, not to make changes to how the resources are procured.** What we're hearing as consensus: Targeted DERs, activities. Targeting activities to customer class, location, specific activity where you will get the most savings. The CE would be better. That's a program design question. The other half of that is the way you count the savings. **But neither is a change to the CE Framework itself.**

G. Commission Process to Accomplish Phases 2 and 3 Goals.
[Morgenstern, CPUC]: What are we avoiding? How do we want to do things differently? Phase 2: Coordinating w/DRP, looking at local level, make sure that CE framework is in synch with LNBA in DRP. Not clear currently *how* we should do that. IOU applications are not very extensive. Suggests that DER may provide value, but nothing in DRP that proposes method of measuring avoided cost of DERs in general. What do we do in the absence of info from DRP? Is there something we want to change in the ACC in the meantime on how to value the distribution elements of DERs? How do we coordinate w/DRP? Currently we have a rudimentary way of calculating distribution values of DERs?
[Borden, TURN]: Would like something more granular. Should not create an LNBA method in this proceeding will be superseded in the DRP.
[McCawley, SDG&E]: Still waiting for ruling on ICA to do Demo projects. Only after then do we have something such as localized avoided costs. It's only a temporal issue because DRP's schedule is slower than IDER.

[Buch, ORA]: Phase 3 -- getting consensus may be beyond the scope and capability of a working group – perhaps better left for mechanisms in the Commission?
[Gersen, Sierra Club]: Social Cost Test in Phase 3 is crucially important. The Commission can begin making progress on the SCT now because it does not rely on the DRP.
[Morgenstern, CPUC]: Could use different mechanisms for different issues. Phase 3 issues are mixed, some of which we couldn't reach a consensus on because they required more discussion and research. Sometimes simply presenting a list to the decision makers of pros and cons could be helpful. [For example, people in this group may never agree on whether or not we should use a social cost test.] Asking members to think about this. **We should have a more discrete list of Phase 3 issues. May meeting will be on E3's ACC update.**

H. Attendees (in person and phone):

Karey Christ-Janer, Independent Consultant
Adrienne Kandel, California Energy Commission (CEC)
Brian McCullough, CEC
Kellie Smith, California Energy Efficiency Industry Council (CEEIC)
Barbara Barkovich, California Large Energy Consumers Association (CLECA)
Sahm White, Clean Coalition
Nathan Barcic, California Public Utilities Commission (CPUC)
Paula Gruendling, CPUC
Natalie Guishar, CPUC
Joy Morgenstern, CPUC
Amy Reardon, CPUC
Brian Horii, Energy + Environmental Economics (E3)
Renee Guild, Global Energy Markets
Christine Hungeling, ITRON
Merrian Borgeson, Natural Resources Defense Council
Diana Genasci, Pacific Gas and Electric (PG&E)
Luke Nickerman, PG&E
Ron Helgens, PG&E
Dan Buch, Office of Ratepayer Advocates (ORA)
Tim Drew, ORA
Helena Oh, ORA
Maya Alunkal, Southern California Edison (SCE)
Dan Harper, SCE
Devin Rauss, SCE
Joe McCawley, San Diego Gas & Electric (SDG&E)
Kevin McKinley, SDG&E
Sara Gersen, Sierra Club
Andrew Nih, Southern California Gas (SoCalGas)
Mike Nguyen, Southern California Renewable Energy Network (SoCalREN)
Jaclyn Harr, Solar City
Eric Woychik, Strategy Integrations
Eric Borden, The Utility Reform Network (TURN)

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Appendix D

Phase 1 Cost Effectiveness Working Group [CEWG] in the Integrated Distributed Energy Resources [IDER | R 14-10-003] Proceeding

Monday, May 16, 2016 | Golden Gate Room, CPUC

Energy Division Summary of May 16, 2016 CEWG Meeting

A. Avoided Cost Calculator/Model Update [E3 Presentation, Followed by Q&A]

Overall Timeline: Draft Avoided Cost Calculator with all the changes by June 1. Feedback and incorporate all necessary edits/changes into final form by July 1. Use for IOU's EE business plan filings Sept. 1, 2016 and DR filings in January 2017.

1. Scenario Assumptions. LTPP scenario to include an SB 350 case, which will be used. E3 suggests using natural gas price forecast, to which there were no objections. T&D avoided infrastructure costs will be reported separately. There needs to be a separate hourly allocation factor, which we do not currently have.

   - [Morgenstern, CPUC]: Breaking out T&D is not really useful in EE, but maybe in DR. If there is too much work, we should not take this on.
   - [Ming, E3]: The DR template already pulls out that piece. Do we pull out of the DR line-item cost calculator to use in the EE?

2. Curtailment. Real costs associated with curtailing renewable energy. EE programs cause renewables to be curtailed, thereby decreasing the value of EE, but EE is first in the loading order. Hence, how do we address this? Curtailment costs are not currently in the Avoided Cost Calculator, hence E3 would like to know if we should include this.

   - [Morgenstern, CPUC]: We don't have authority to do that.
   - [Ming, E3]: E3 will create a place holder to capture amount of curtailed in renewables.

3. Resource Balance Year. RBY is factored in so that any year can be entered.

   - [Castle, SCE]: Loss of Load (LOL) or unserved energy? (Unserved energy is preferable.)
   - [Ming, E3]: Loss of load expectation. We're looking at a system that is at a target level of reliability as the base state. Unserved energy hours give more value to actual unserved hours, whereas LOL gives too much value to weekend hours. It's also been used in the model.
   - [Woychik, Strategy Integrations]: Agree with Dave Castle.
   - [Morgenstern, CPUC]: E3 is identifying that change in load shapes due to rooftop solar – the current method uses historic load shapes going forward. So we're not suggesting making a change for change's sake but a change to *correct* an identified error in the current methodology.
   - [Woychik, Strategy Integrations]: Each IOU had their own presentation/method on this issue and we do not support PG&E's method.
   - [Morgenstern, CPUC]: Since we can't get to agreement, we will allow stakeholders a week to provide position and go with majority.

4. Allocating Transmission and Distribution (T&D) Factors. Currently based on temperature, which does not capture true basis of distribution peaks. E3 developed new T&D allocation factors based on building code criteria. Factors will be based on loads, according to climate zone, not just temperature.

    - [Morgenstern, CPUC]: Allocating on temperature is a mistake. Two fundamental questions: The method to calculate avoided energy is fundamental, so should we or should we not be correcting an error? If it is within the scope of correcting errors, then which method? (PG&E's, CAISO's RPS approach, etc.?)
    - [Ming, E3]: Any change is better than what we have now.

5. Estimation vs. Simulation Approach. Do we include renewable curtailment? Is that a fundamental model change or an improvement for the sake of accuracy?

    - [Buch, ORA]: E3 mentioned that you "could" adjust the belly of the duck, but you didn't explain what. Putting stakeholders in a difficult position to make a decision on something that could become a precedent.
    - [Ming, E3]: Both models attempt to capture the cost of curtailment in the price shape. The key questions are: How is price shape impacted by renewables, and how to capture the value of curtailed renewables?

B. Phase 3 Issues.

There is a draft Proposed Decision (PD) on the CEWG status report. Accordingly, this should be characterized as incomplete pending additions from today's discussion and results of Commission decision on PD. Specifically, the draft PD made a ruling on the Resource Balance Year (RBY). Since currently there is neither a PD nor a Commission decision on this issue, the RBY should be considered a Phase 3 issue pending a final Commission decision on the issue.

- [Baker, CPUC]: Funding in PD for technical assistance for Phase 3 issues. Some policy issues: Thinking more towards staff proposal white papers, et. al. In going thru Phase 3 issues, what role do we think WG could have to be helpful and constructive? Want to hear if folks think they can add value.

H. Attendees (in person and phone):

Karey Christ-Janer, Independent Advocate
Adrienne Kandel, California Energy Council (CEC)
Elena Giyenko, CEC
Kevin Smith, CEC
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Other Information:
For procedural details relating to the Integrated Distributed Energy Resources [IDER] proceeding [R. 14-10-003], commenting and the record development process, and the role of this working group meeting within the proceeding, please refer to the "Administrative Law Judge's Ruling Directing Comments to be Filed on February 2, 2016 Status Report of the Integrated Distributed Energy Resources Working Group," issued on February 29, 2016.

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