Net Energy Metering Cost-Benefit Study

Phase 1 Scope and Method

Post-workshop Update

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Energy+Environmental Economics

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

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Phase 1 Scope and Method

1 Background

The CPUC has contracted with Energy and Environmental Economics (E3) to provide an evaluation of the costs and benefits of the Net Energy Metering (NEM) program. This study fulfills the requirements of Assembly Bill (AB) 2514 (Bradford, 2012) and Commission Decision (D.) 12-05-036, which requires a study on the costs and benefits of NEM and an analysis of "who benefits, and who bears the economic burden, if any, of the net energy metering program," by October 1, 2013. This study will also serve as an update to the CPUC's 2010 NEM Cost Effectiveness Evaluation (2010 NEM Study).

NEM is an electricity tariff that facilitates the deployment of on-site distributed generation (DG) used primarily to offset load. Under NEM tariffs, customers receive a bill credit based on the full retail rate for any excess generation that is exported back to the grid - including generation, transmission, and distribution rate components. In periods when the bill is negative (because the value of the energy produced by the DG facility exceeds the value of the energy consumed on site), the negative balance is carried forward up to one year. Eligible customer generators who produce electricity in excess of on-site load over a 12-month period may elect to receive net surplus compensation, or apply the net surplus electricity as a credit toward future consumption.

The NEM study will be completed in two phases:

Phase 1: Net energy metering ratepayer impact. The first phase of this project will be to calculate the ratepayer impacts of NEM for all participating technologies (solar, wind, fuel cell, microturbine, etc.) using the best available data and information. The analysis will be performed at two penetration levels: the capacity needed to reach the solar photovoltaic goals of CSI and the net metering cap as defined by D. 12-05-036.

Phase 2: White paper on NEM alternatives (subject to budget availability). In a separate white paper, the second phase of the study will be to compare alternatives to NEM using a framework that highlights the balance between the financial proposition for customers to install renewable DG and the overall impact to ratepayers.

1.1 Proposed methodology for NEM Study – Phase 1

The methodology and scope of work outlined below reflects stakeholder feedback following the October 2012 stakeholder workshop. Responses to stakeholder comments are provided in Section 4 of this report.

The approach in this study is similar to the 2010 NEM study, with the following substantive changes:

+ The dataset will be expanded to include all NEM customers through December 31, 2011. Because a significant amount of actual interval data has been made available since the 2010 evaluation, the quality of the underlying dataset has been improved. Much of the dataset is confidential (billing records, PV output, AMI data). However, summarized data in a single spreadsheet tool will be made publicly available, including (a) non-confidential characterization of NEM customer consumption / production, (b) retail rate calculation, (c) forecast of impacts.

+ The study will evaluate exported energy delivered to the grid and compensated through NEM and the entire generation output of the NEM generator, consistent with AB 2514.
+ The study will be performed at multiple NEM penetration scenarios, including at a minimum the capacity needed to reach the solar PV goals of CSI and the net energy metering cap as defined by D. 12-05-036.
+ The retail rates of NEM customers will be updated to reflect current rates, as will the estimate of future retail rate escalation.
+ The study will disaggregate results by utility, customer class, and household income groups within the residential class, Per D. 12-05-036. For the income distribution of residential NEM participants, results shall be grouped by census block.
+ The study will evaluate the degree to which NEM systems pay their full cost of service, consistent with AB 2514.
+ The avoided cost estimates will be updated to reflect methodology changes implemented by the CPUC, and to revisit key drivers of NEM cost-effectiveness. The extent of avoided cost updates will depend in part on available budget and time. We expect to:
    - Update natural gas prices consistent to current futures market projections, using the existing CPUC MPR methodology
    - Update the RPS premium calculation

- We plan to make two methodological updates to the avoided costs for this study. Since these changes have not yet been adopted by the CPUC, we plan to calculate avoided costs two ways: with these updates and using the prior methodology. The two methodological changes are:
    - Improve the assessment of distribution system coincidence between NEM systems and distribution loads
    - Improve the assessment of generation system coincidence for purposes of evaluation effective load carrying capability of systems
- A number of helpful stakeholder comments were received in addition to the avoided cost updates referenced above. To the extent there is budget and time to perform sufficient analysis, we will also:
    - Recalculate forward looking avoided costs of transmission and distribution using the present worth method based on utility capital planning data rather than the GRC marginal cost estimates
    - Update the resource balance year to include vintage and consideration of the type of resource in the loading order
    - Evaluate the impact of future electricity market prices in the context of a changing supply portfolio over time
    - Perform a more detailed assessment of the CAISO system costs to integrate NEM generation resources.
    - Update the forecast of CO2 prices considering the ARB auction and forward prices of California CO2 allowances

2 NEM Cost-Benefit Study

Our evaluation is limited to the effect of NEM on ratepayers; results of the study will not speak to the overall societal value of the renewable DG under NEM, nor will they establish the wisdom or value of policies that stimulate or incentivize renewable DG.

Specifically, the study will compare the following ratepayer costs and benefits[1]:

- Ratepayer costs
  - Bill reductions resulting from NEM mechanism
  - Incremental billing and admin costs for NEM
  - Interconnection costs not paid by the customer
  - System integration costs
- Ratepayer benefits
  - Utility avoided costs of otherwise supplying energy to meet the load

[1] These costs and benefits are consistent with the methodology for calculating the Ratepayer Impact Measure (RIM) test, as defined in the California Standard Practice Manual for economic analysis of demand-side programs and projects: *http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF*. This methodology was adopted for evaluation of distributed generation in CPUC D.09-08-026.

The 2010 NEM Study, also conducted by E3, was similar in scope. Once complete, the ratepayer impact calculated in the present report can be directly compared to the results of the 2010 study to suggest trends over time.

2.1 Export Only versus All NEM Generation

In evaluating costs and benefits of NEM, AB 2514 directs the Commission to "consider all electricity generated by renewable electric generating systems, including the electricity used onsite to reduce a customer's consumption of electricity that otherwise would be supplied through the electrical grid, as well as the electrical output that is being fed back to the electrical grid."[2]

An exact measure of the effect of NEM on ratepayers would compare the state of the world with NEM to that without NEM, and calculate the ratepayer costs under both. The state of the world with NEM is the world we live in, and can be calculated with actual measured data. The state of the world *in the absence of NEM*, however, is a counter-factual condition that is not completely knowable. It's not certain exactly how much renewable DG would have been installed in California without NEM, nor precisely how customers might have sized DG differently or changed their electricity usage to better align with renewable DG output. At best, we can make educated estimates of customer behavior in the absence of NEM.

Because it is not possible to know for certain how much DG would have been installed in the absence of NEM, this study will consider and present two

[2] Assembly Bill 2514 Net Energy Metering, approved by the Governor and filed September 27, 2012. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201120120AB2514

"bookends" to represent the possible range: (1) consideration of export energy only (NEM-Export), and (2) consideration of all generation (NEM-Generation), both export and direct offset, which satisfies the requirement of AB 2514 to "consider all electricity generated...".

2.2 Disaggregation of Results by Customer Type and Public Purpose Program Effects

AB 2514 further requires that the study "disaggregate the results by utility, customer class, and household income groups within the residential class" and that the study "determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs."

We will disaggregate results by utility and customer class and estimate the effects of NEM on residential customers of various income strata. The study will also consider the extent to which customers pay the full cost of services provided and the effect of NEM on the collection of nonbypassable volumetric charges, including public purpose programs, the California Alternative Rates for Energy (CARE) program, the Energy Commission surcharge, nuclear decommissioning, DWR bond charges, energy cost recovery charges, and competitive transition charges (CTC).

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3 Methodology

Our calculation of costs and benefits involves three key steps, described in more detail below:

+ Development of hourly load and output profiles
+ Bill calculation
+ Avoided Cost calculation

3.1 Development of Hourly Load and Output Profiles

In the 2010 evaluation, we used limited available data to develop representative "bins" of customers. Each bin contained customers that were similar or identical with regard to utility, climate zone, rate schedule, level of customer load, size of renewable generator, and ratio of generator output to load. In all there were more than 1,200 bins, which represented "typical" load and output profiles given the characteristics delineated above.

For this study, we have been able to obtain somewhat more detailed data. This data will allow us to develop individual load and generation profiles for the majority of NEM customers.

3.1.1 GENERATION PROFILES

We have metered output profiles for a significant minority of NEM generators (several thousand). For the remainder, we will use an in-house simulation tool to develop output profiles using SolarAnywhere weather data, based on generator characteristics (type, size, etc.) which are available for the vast majority of NEM accounts.

3.1.2 LOAD PROFILES

We have hourly or sub-hourly metered load profiles from utility load research data. These load profiles will be sized to customers based on customer characteristics such as total load, location, rate schedule, etc. In addition, we have metered hourly bi-directional *net* load for several thousand customers. When combined with DG output profiles, these bi-directional net load profiles provide additional gross load profiles that can be sized to similar customers.

Combining the generation and load profiles on an individual customer basis provides us with all the information needed to calculate the bill effects of NEM and the avoided costs. This is true whether we evaluate just the hours of export to the grid or all generation including direct offset of consumption (as noted above, this study will include both).

As mentioned above, we will be able to develop hourly load and generation profiles for the majority of, but not all, customers. For the remaining customers, we will make some estimate of NEM costs based on extending the data we do have to represent those customers where data is lacking. The precise method for this is to-be-determined, but may involve binning as used in the 2010 NEM evaluation.

3.2 Bill Calculation

We have developed an Excel-based bill calculator. From the 8,760 load profiles, we will develop billing determinants necessary to calculate bills for each of the major rate schedules.

To calculate the bill effects for the NEM-Generation scenario (both export and direct offset), we will compare a bill that would occur under the gross load shape without DG to a bill that would occur under NEM (from the actual billing records). The difference between the two bills is the reduction in billing revenue from NEM. In the NEM-Generation scenario we will also disaggregate the amount of public purpose charges and other volumetric charges that are avoided through the direct load offset.[3]

To calculate the bill effects in the NEM-Export scenario, we will compare the bill that occurs under NEM (from the actual billing records) to the bill that would occur if the meter were not allowed to spin backward; that is, if the same amount of generation were to occur, but all exported energy were shed. In the NEM-Export case we will also compute standby charges for rates where standby charges would otherwise apply which are generally non-residential rates. Since the NEM statute explicitly forgives these customers' standby charge obligations, NEM customers would potentially be obligated to pay standby costs for their

[3] AB 2514 requires the NEM benefit-cost study to identify "the extent to which [NEM] customers pay their share of the costs of public purpose programs." (Section 1(a)).

self-generation without the legislation. We will also do a sensitivity to our base case results that assumes standby charges and departing load charges would be exempt in the absence of NEM, as delineated in the sensitivities section below.

3.3 Avoided Cost Calculation

The E3 avoided cost methodology was first adopted for evaluation of energy efficiency programs in CPUC Decision (D.)05-04-024. Subsequently, the use of the E3 avoided cost methodology has been expanded to include other demand-side programs, such as demand response. The CPUC adopted the E3 avoided cost methodology, with some modifications, for use in evaluating distributed generation in D.09-08-026.

Under this methodology, avoided costs are time- and location-specific, calculated for each hour of the year. Avoided costs include the following components:

Table 1: Components of electricity avoided cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of carbon dioxide emissions associated with the marginal generating resource

Line Losses	The loss in energy from transmission and distribution across distance
Avoided RPS	The cost of purchasing renewable resources to meet an RPS portfolio that is a percentage of total retail sales

The hourly granularity of the avoided costs is obtained by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices and actual system loads reported by CAISO's MRTU system; Table 2 summarizes the methodology applied to each component to develop this level of granularity.

Table 2: Summary of methodology for electricity avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Market forwards that transition to the annual average market price needed to cover the fixed and operating costs of a new CCGT, less net revenue from day-ahead energy, ancillary service, and capacity markets.	Historical hourly day-ahead market price shapes from MRTU OASIS
System Capacity	Fixed costs of a new simple-cycle combustion turbine, less net revenue from real-time energy and ancillary service markets	Hourly allocation factors calculated as a proxy for LOLP based on CAISO hourly system loads. If time allows, the system capacity allocation method will be updated to use the Expected Load Carrying Capacity (ELCC) method that has been proposed for Demand Response.
Ancillary Services	Scales with the value of energy	Directly linked with market forecast for energy

T&D Capacity	Survey of utility marginal transmission and distribution capacity values from general rate cases and utility project forecasts.	Hourly allocation factors calculated using weather data as a proxy for distribution loads. If time and budget allow, the method will be updated to use actual hourly distribution loads at the substation or feeder level, with each customer's PV output mapped to the appropriate substation or feeder.
Environment (CO2 reduction)	Implied cost of CO2 in the forward electricity markets.	Directly linked with energy shape through implied market heat rate with bounds on the maximum and minimum hourly value
Environment (criteria emissions)	Capitalized cost of procuring emissions permits (NOx, PM10)	Linked to the generation capacity value
Avoided Renewable Purchases	Based on CPUC Legislative Reporting under SB 836 and renewable premiums observed in the Renewable Auction Mechanism (RAM).	Flat across all hours

3.4 Sensitivities

We will conduct the sensitivities described in Table 3. Sensitivity testing will apply to all three penetration scenarios (see Study Results section below).

Table 3: NEM Benefit-Cost Sensitivities

Sensitivity	Description
T&D Avoided Costs	There is disagreement as to whether utilities can really avoid T&D investment as a result of DG. The sensitivity case will calculate results without T&D avoided capacity value.
Natural Gas Prices	Currently, natural gas forward projections are historically low. We will test a higher alternative natural gas price forecast as a sensitivity in our forward-looking analyses.
Electricity Rate Escalation	We will develop high and low retail rate escalation forecasts.

Billing and Administration	PG&E NEM billing costs remain high relative to the other utilities. We will test alternate billing costs under the assumption that these processes will cost less over time.
Interconnection	Only limited interconnection cost data on non-reimbursed ratepayer costs was available. We will test a range.
Standby Charges	We will calculate results in a sensitivity analysis under the assumption that standby charges and departing load charges would not be assessed in the absence of NEM.
CO2 Price	We will calculate a low and a high sensitivity with the CO2 price at the CO2 allowance price floor and ceiling.
Load/Resource Balance Year	We will evaluate a sensitivity analysis whereby NEM generation receives the full generation capacity throughout the study horizon rather than a future resource balance year.

3.5 Study Results

We will produce the following results:

+ Estimated net ratepayer cost in 2011 for all NEM generation installed through 2011.
+ Estimated contribution of NEM customers to their full cost of service.
+ Lifecycle net ratepayer cost for all NEM generation installed through 2011, with sensitivity testing.
    - Breakdown of lifecycle results into groups of like customers, household income groups, utilities, climate zones, etc.
+ Forecast of net ratepayer cost at full CSI program subscription and at the 5% NEM cap, with sensitivity testing.
+ The income distribution of residential NEM participants, grouped by census block.

+ Non-confidential dataset representing NEM customer size and generation data aggregated into 'bins'.

Results described above will be calculated for both the "export only" and "all NEM generation" scenarios.

In addition, we will produce a public calculation tool, populated with non-confidential billing and avoided cost data that will allow stakeholders to follow the calculations and review the methodology and study results.

4 Replies to Comments on NEM Methodology

In this section, we respond to comments received following the NEM stakeholder workshop. Comments are organized by subject area. On the whole, we found the comments very thoughtful and constructive, and have attempted to adopt, within time and budget limitations, those that we feel will improve the accuracy of the results. Given the available budget and time, it is unlikely that we will be able to incorporate every suggestion. Therefore, we have focused on improving key drivers to the extent that we can, with sensitivity analyses to provide ranges on others.

Many comments were related to the avoided cost methodology. While our original approach was to use the established avoided costs applied in the energy efficiency and other distributed resource proceedings, we found merit in many stakeholder comments regarding the avoided cost methodology, and as a result are proposing some significant avoided cost methodology updates. If undertaken, the avoided cost methodology update would include the following components:

+ **Generation Capacity Resource Balance Year (RBY).** Update the RBY based on latest data (load forecast, OTC retirements, RPS contract, energy efficiency estimates, etc.). In addition, propose a methodology to evaluate RBY by specific resource types in consideration of the loading order. Finally, address the vintage issue with different RBYs possible for different install years.

+ **Generation Capacity Allocation.** Based on an Effective Load Carrying Capacity (ELCC) model.
+ **Energy and Capacity Value Allocation.** Use actual weather for historical years coincident with market prices and remap actual days to align with similar weather days.
+ **Transmission Avoided Cost.** Consider transmission avoided costs that are both utility and CAISO jurisdictional, with variance by local capacity zone. Estimate would use most recent utility transmission expansion plans and FERC-jurisdictional transmission costs at the CAISO.
+ **Distribution Avoided Cost.** Based on the most recent distribution capital plans, load growth estimates from each utility, and the present worth method to calculate avoided costs by distribution area.
+ **Distribution Capacity Allocation.** Use actual hourly (or more granular) distribution load data to determine coincidence of load reduction with peak distribution system loads, rather than the current temperature-based proxy.
+ **Ancillary Services.** Disaggregate ancillary services bundle into separate elements and appropriately value each given the characteristics of the resource being evaluated. Reductions in spinning and non-spinning reserves would be applicable to distributed generation that reduces CAISO system loads.
+ **RPS Adder.** Use actual renewable procurement costs rather than the RPS Calculator planning tool. The most recent released data from the renewable RFOs on pricing, or the Renewable Auction Mechanism market clearing prices, are a potential source.

- **Natural Gas Price.** Update the natural gas price forecast using the most recent available information.
- **CO2 Price Forecast.** Develop an approach that considers ARB auction price data and futures market for allowances.

These updates would potentially apply to other distributed resource types, such as energy efficiency and demand response, and therefore need to be coordinated with the appropriate proceedings.

The degree to which schedule and funding will allow for such an update is yet to be determined. It is likely that some methodological updates to the avoided cost methodology may be accommodated, while others will be deferred. In the event avoided cost updates occur *after* the completion of the project, a new set of results can be run with the updated avoided costs and an addendum to the report published.

Below are our responses to comments, loosely organized by topic area.

4.1 T&D Avoided Costs

[DRA] The "snapshot" analysis should use more geographically-specific avoided costs.

> RESPONSE: To manage project scope, E3 will use the same level of geographic disaggregation for the "snapshot" analysis (2011 year only) as for the rest of the analysis. Subject to time and budget constraints we intend to evaluate avoided costs at a greater level of geographic specificity, such as by developing distribution system coincidence factors.

[IREC] SEIA has found bulk transmission avoided costs are not included in E3's AC calculator. They should be. Also marginal costs for T&D should be from the most recent GRC or the 2011 MPR, approved in Resolution E-4442.

[see response below]

[SEIA/Joint] E3's avoided T&D costs do not include FERC-regulated high voltage. In its 2005 GRC (A. 05-05-023), SCE used $23.32 per kW-year as its marginal cost for FERC-regulated transmission. Also, the study should use latest GRC T&D avoided costs, which are higher.

RESPONSE: We will use the most recently available marginal cost estimates in the study.

To the extent available, we are considering using transmission and distribution capital cost planning data of upcoming projects to estimate forward looking avoided cost estimates for distribution and transmission rather than the marginal costs used for ratemaking based on historical expenditures.

We have proposed an avoided cost update which would use:

- Marginal avoided transmission costs from the most recent utility transmission expansion plans (to the extent such costs would not already be embedded in the generation market prices).
- Consideration of FERC-jurisdictional transmission costs at the CAISO
- Distribution avoided costs based on the most recent utility distribution capital plans, load growth estimates, and use of the present worth method to calculate avoided distribution costs by planning area. Distribution capacity allocation would be calculated two ways: (1) under the current method using temperature as a proxy for peak loads and (2) using actual hourly distribution load at the substation or feeder level Results would be presented separately for each.

If we are unable to include these updates to the T&D methodology due to time or budget constraints, we will use the existing methodology (though verify appropriate data sources). An update can be computed when new avoided costs using the updated method are available.

[PG&E] "It is inappropriate to include any quantification of T&D upgrade deferrals in the base case of the cost shift calculations. In the first place, the proposed methodology does not conform to D.09-08-026 because it does not include the analysis required to estimate T&D benefits [Itron method]. Second, even the existence of T&D deferral benefits has been controversial, with many parties arguing that NEM technologies do not possess the key characteristics"

RESPONSE: The Itron method is used for EM&V and has no direct application in a planning context. We see no way to use it in this manner, and are not sure why the Commission adopted it for forecasting. E3 was the subcontractor to Itron for the study cited in D.09-08-026 and that study was an analysis of existing generation relative to distribution system needs. The closest proxy to the Itron method that could be used is the evaluation of the capital budget plans and the present worth method to calculate avoided costs.

[TURN] Against using weather data to allocate T&D costs. Residential feeders peak around 6:00-7:00, not the hottest hours. Should exclude residential class from T&D benefits, or make analysis circuit specific based on circuit load data.

[see response below]

[SCE] "E3's DG avoided cost calculator does not properly measure avoided T&D costs, because the E3 calculator allocates T&D capacity cost savings based upon temperature. Temperature is a sub-optimal proxy for circuit loads, especially when actual circuit load profiles are available. Specifically, many of SCE's residential circuits peak in the evening after residents return home but well after temperatures reach their maximum values" E3 should take this into account, and show res and non-res avoided T&D separately.

RESPONSE: E3 concurs that the use of actual circuit or substation data would be superior to the use of the extant temperature proxy. As the temperature proxy method is the currently adopted method, E3 proposes to calculate the value two ways: (1) under the current temperature proxy method and (2) using substation or feeder-level load data to allocate T&D costs if time and budget allow. This is still being determined with the CPUC as one part of many possible avoided cost updates.

[SCE] Study should also explicitly differentiate between T&D marginal costs that are typically included in the IOUs' general rate case (GRC) proceedings and the avoided costs that should be used in the cost-effectiveness study. Avoided T&D costs are lower than marginal cost because a utility service would still be required to connect the customer to the grid regardless of any reduction in demand. The value E3 is using contains an error by including these O&M costs such as poles, wires, land, buildings, thereby overstating the avoided T&D costs by 100% (E3 independently added O&M to the avoided T&D values SCE provided in a data request).

> RESPONSE: E3 will work with SCE to produce an improved estimate of demand-related avoidable costs for use in the study. E3 concurs that O&M for items such as poles should be excluded from avoided T&D costs. However, O&M for items such as new transformer banks should be included.

4.2 Other (Non T&D) Avoided Cost Comments

4.2.1 GENERAL

[SEIA/Joint] E3 appears reluctant to, but should use 2011 MPR input assumptions for avoided costs, which are more up-to-date and were approved by the Commission in December 2011.

> RESPONSE: The 2011 MPR only provides an estimate of the all-in costs of a CCGT. This provides some of the necessary inputs, but far from all of them. The MPR does not disaggregate costs by time or year, or address T&D, RPS, A/S, or losses. The established framework developed for distributed resources such as energy efficiency is a much better starting point for this analysis. As discussed in this document, we will include key updates to the avoided cost methodology and inputs.

4.2.2 GENERATION CAPACITY VALUE AND TIMING OF SYSTEM PEAK

[IREC] In theory, capacity value is not taken away from existing resources in favor of new ones. The logic is that capacity value was assigned to the old resources, and those resources were financed and built on the basis of that established capacity value. However, the loading order for resources puts energy efficiency and renewable energy at the top; they will actually be used. It seems counterintuitive to assign minimal capacity value to certain resources being used to meet peak loads, while assigning higher value to resources that sit idle.

> RESPONSE: Calculating the capacity value of resources of different vintages and of different resource types is certainly complex and we will estimate it the best we are able given the time and resources. Theoretically, an NEM generator's capacity value should be based on the vintage when it was installed. In addition, we should not include the generation from a new NEM system in the calculation of the RBY for the NEM system. There is also a loading order issue. Should we include the load reductions from energy efficiency before calculating the RBY for NEM generation since efficiency is first in the loading order? Our original proposal was to make a simplifying assumption and use the RBY from energy efficiency of 2017. This is the current estimate of RBY without any incremental impacts of EE, NEM, and CHP and with SWRCB OTC retirement schedule. We will present results using the 2017 RBY and, to the extent we have time and resources we will develop an update using the Expected Load Carrying Capacity (ELCC) model.

[SDG&E] E3 indicated in their presentation that they were not going to update the avoided costs recently approved for use in the 2012-2014 Energy Efficiency applications. By ignoring the large change in expected peak net of variable renewable energy, the avoided capacity costs at various times of the day will be incorrectly calculated. All the CAISO and E3 studies indicate the peak load net of variable renewables will shift to evening hours by as early as 2016. As that shift in peak takes place, the capacity value of solar PV diminishes as it does not produce after the sun sets. The choice to ignore this future reality would seem to invalidate the study results before the study is even undertaken. Taking this shift in peak load net of variable renewable generation into account should not be difficult since E3 has done analysis of the issue and has calculated the shifting peak for other analyses. Allocation of capacity value across hours should be updated from the use of the top 250 hours on a historical basis pre-2011 data to using expected load net of variable renewable generation to reflect this change in economics over time. Similarly, though less important than the impact on capacity, is the impact of variable renewable generation on the hourly shape of marginal energy costs. Large increases in variable renewable energy will drive down relative prices in mid-day hours (solar) and middle-of-the-night hours (wind) in the future. E3 has done production cost modeling that could be used to quantify the change in hourly price profiles used in the Study.

> RESPONSE: We agree that we should improve the capacity allocation approach. E3 is currently working on an improved capacity allocation using an ELCC model and forecasts of the changing supply portfolio into the future. If completed, we intend to use these improved estimates to value the capacity of the NEM generation, in addition to using the existing method for calculating capacity value.

[TURN] "Reasonable forecasts indicate that when wholesale solar projects, whose output is contracted on a must-take basis pursuant to RPS-eligible power purchase agreements, come on line in 2013-2016, the resulting increase in solar generation output during the 12-3 p.m. period will fundamentally alter wholesale market prices for energy, and wholesale contract prices for capacity."

> RESPONSE: We agree that the shape of the wholesale market prices would be expected to change over time as California's resource portfolio changes. As SDG&E points out in their comments, past E3 studies have looked at this. However, this has never been incorporated into a distributed resource value since the impact of DG itself on market prices is expected to be small. To the extent budget and time constraints allow, we will evaluate the magnitude of the effect and include it in the study. We may need to integrate this effect into a broader 'market price' sensitivity rather than do detailed analysis.

4.2.3 ANCILLARY SERVICES

[PG&E] "E3 proposes to include a benefit based on a theoretical reduction in ancillary service requirements due to reduction in load from customer-installed NEM generation. This is incorrect. For all of the reasons described above when discussing integration costs of renewable generation, it is inappropriate to assume there is any reduction in ancillary services. Today's ancillary services are primarily contingency reserves (spinning and non-spinning reserves), as well as regulation up and down. Contingency reserves are intended to cover major resource or transmission contingencies, which do not change because of NEM. Regulation services actually increase as a result of additional wind and solar intermittent generation. Consequently, ancillary service benefits should be excluded from the analysis and integration costs should be substituted."

RESPONSE: Our understanding is that reserves are purchased roughly proportionally to load that the CAISO serves. Thus, a reduction in load from NEM generation results in a savings in the cost of reserves just like energy efficiency. We do not include other types of ancillary services that are not dependent on load level, such as regulation, in our avoided costs. Also, remember that we separately consider increases in ancillary services costs for integration, for example increased need for regulation, which is discussed below.

[TURN] E3 would calculate ancillary services avoided costs at 2.84% of the energy cost. But rapid changes in solar output may actually result in increased ancillary services costs.

RESPONSE: See above. This represents the reduction in the purchase of reserves because the CAISO is serving less load and can more easily accommodate its planning contingencies with the NEM generation. We discuss ancillary services cost increases below.

4.2.4 AVOIDED RPS

[SEIA/Joint] Should count more than 33% avoided RPS: "It may be argued that this added penetration of renewables above the 33% RPS requirement is an additional, "societal" benefit that does not impact the utility revenue requirement. Thus, the argument goes, this added penetration of renewables is not a direct benefit for utility ratepayers and should not be included in the analysis. The Joint Parties strongly contest this perspective. California is depending on both the RPS and renewable DG programs such as the California Solar Initiative to meet its GHG and clean energy goals. Without the CSI, for example, the RPS % would have to be increased to above 33% in order to achieve the same GHG emission reduction goals from renewable electric generation. This shows that the increased renewable penetration from the CSI does have a direct financial benefit for ratepayers.

[IREC] We have an RPS, but no way for IOUs to purchase NEM RECs, so essentially the legislature is saying energy must be more than 33% renewable. SEIA's proposal is therefore reasonable.

[PG&E] "there is no avoided [RPS] cost for nonparticipants, since almost all the exports are credited to the participating customers as sales reductions, so the IOU does not receive any generation procurement, regardless of the renewable nature of the generation source. The only renewable generation that the IOUs may potentially receive on behalf of non-participating customers is the annual excess generation compensated under the rules established in AB 920" Furthermore, with the current "bucketing" limits in the RPS, potential REC value is low.

[DRA] Considering NEM exports valued at 100% of renewable premium is out of scope because it is a societal test.

> RESPONSE: We agree that it is not correct to value 100% of the export as saving the renewable premium, as the avoided costs are intended to measure direct savings to ratepayers, and ratepayers must still purchase renewables to meet the RPS (since the NEM export does not count toward the RPS). Commenters make the argument that the state has set not just RPS but also GHG goals, and that the renewable premium is a reasonable proxy for the ratepayer cost of whatever additional measures the CPUC would need to take to meet GHG goals in the absence of the RPS. However, in our view this connection is too tenuous to be included in the analysis because the GHG goals are economy-wide and it is not clear where the GHG savings in question would come from, nor to what extent the impact would be on ratepayers.

[PG&E] Avoided RPS purchases will be at a lower premium in the future, likely below $50/MWh.

> RESPONSE: We will evaluate the approach used to estimate the premium and calculate a new premium based on updated data (from CPUC Legislative Reporting under SB 836 and the RAM solicitation) and avoided costs consistent with the rest of the analysis. This market data was not available when the original estimate was made using the RPS Calculator. We note that in the current model, the RPS premium does decline over time, and in the version used for the 2013-2014 EE avoided costs, the premium drops below $50/MWh in 2023.

4.2.5 RESOURCE BALANCE YEAR

[PG&E] "PG&E recommends that the energy efficiency forecast should be restored to the load forecast used to determine the avoided cost curve and the rooftop solar forecast should be removed. This will ensure the appropriate calculation of, in particular, avoided capacity costs."

[SCE] Workshop chart says 2017 RBY, document said could be post-2020. SCE supports post-2020.

[IREC] If E3 uses CAISO projections for RBY, should be moved up 3 years to 2014, because distributed solar is not counted in CAISO's stack of capacity resources. Projected increases in NEM are baked into system-wide forecasts. To determine RBY in absence of NEM, curve should be shifted up by the capacity contribution of NEM facilities.

[DRA] RBY should not be assumed to be the current year, even in a sensitivity. It may be reasonable to use an earlier RBY for LA Basin or San Diego, where there are local capacity issues.

> RESPONSE: If time and budget allow, we will propose a methodology to evaluate RBY for specific resource types, with consideration of the loading order. As described above, the 2017 RBY calculated for energy efficiency assumed no new energy efficiency, NEM, or CHP resources. As SCE points out, including new energy efficiency impacts would likely move the RBY into the post-2020 timeframe. However, some of the NEM has existed for some time, which brings up the question of vintage. We hope to revisit the RBY calculation if time and budget allow, in addition to the original plan of using the RBY of 2017 from the 2013-2014 EE avoided costs, with sensitivities to bound the range of the analysis.

[SEIA/Joint] "The use of the RBY concept makes little sense when the task is to value the resources installed under a program such as NEM that has been in place in the state since the late 1990s and that has added resources gradually over many years." Other resources, once "committed" are not devalued. The MPR has been used to value RPS resources and is a better measure, more consistent with large scale. In D.10-12-024 the Commission rejected the use of RBY for evaluating DR; the same logic should apply to DG. Also, CA is adding renewable DG for GHG reduction; capacity is irrelevant.

> RESPONSE: Regardless of the policy reason for incentivizing NEM generators, they have capacity value to ratepayers only if it offsets

capacity expenditures that would otherwise be needed. The resource balance year provides an estimate of when that offset to additional capacity may be needed. As discussed above, if time and budget allow, we will update our methodology to consider RBY relative to NEM generator vintage.

[PG&E] "The resource balance year should not be assumed to always be the next year, with the result that the avoided capacity cost is always based on the cost of a new generation unit inclusion of capital avoided costs for the entire life of a NEM generator. Further, most foreseeable new generation additions will be required to be flexible in order to accommodate anticipated integration of renewables. Renewable generators do not have the attributes to avoid the need to acquire this type of resource, and in fact will increase the need for flexibility. Therefore, the RBY for the type of capacity that renewable DG can avoid is probably further out than the actual year that new flexible generation is needed, and the value for non-flexible capacity that renewable generation can help avoid is increasingly less valuable."

RESPONSE: These concerns would be addressed by use of the ELCC method, which E3 is developing as an update to the avoided costs in the DR proceeding. If timing allows, this method will be used for the NEM benefit-cost analysis as well. Also, it is worth noting that the RBY method is designed to identify the year when new capacity is needed purely to meet planning standards for adequate capacity. There is nothing in the RBY method that requires that such new capacity be "flexible" capacity --- only that it be available at the time of the system peak. PG&E's argument does have merit to the extent that if other system needs cause the addition of generation capacity prior to the RBY need year, that new generation would push out the RBY need year. However, all existing and currently authorized new generation has been incorporated into the RBY calculation.

4.2.6 LINE LOSSES

[PG&E] "exports should be treated like any other power source and to assume line loss savings is inappropriate."

RESPONSE: Given the restrictions on NEM system sizing, it is very likely that exports are consumed on the same distribution circuit as the NEM generator. Therefore, the loss reductions on transmission and some distribution are unchanged. There may be some reduction in loss savings on the secondary voltage system, but losses on the secondary system are likely small compared to overall losses. To the extent time and budget allow, we will look into this further, but given the small impact on the analysis this is a relatively low priority. In the first step of this analysis we would compare the difference in total losses between primary and secondary customers as an initial estimate for the reduced loss savings.

4.3 Additional Costs and Benefits that should be Included

4.3.1 INTEGRATION COSTS

[SDG&E] Incremental integration costs should be at least as large as avoided A/S. E3 indicated in Slide 31 of their presentation that in 2011 there were no integration costs. The assumption that E3 plans to make is that there are no integration costs for 20 years in the future. This assumption will be made in spite of the massive effort in California to create new structures to accommodate integrating more variable renewables into the electric grid. The CAISO and CPUC will be requiring utilities to obtain additional capacity for flexible ramping, most likely in winter months. The CAISO developed a new load following energy product. The CPUC is considering expensive energy storage to alleviate grid problems created by the intermittency of variable renewable generation. And it is generally acknowledged that more regulation services will be needed. The assumption that integration costs will be zero seems to be a poor assumption. At a minimum, integration costs should be as large as the proposed avoided ancillary service costs E3 has planned to include as an avoided cost (slide 48). Further, a larger value should be included as a sensitivity based on studies where potential integration costs have been quantified.

[PG&E] "PG&E was disappointed to find that E3 planned to ignore integration costs caused by renewable generation. Integration costs have short- and long-run components and should be estimated just as E3 estimates avoided costs." Short-run A/S such regulation and flexi-ramp. Long run residual fixed costs of flexible capacity. PG&E suggests base case integration costs of $8.50.

RESPONSE: We are not ignoring integration costs, we just don't believe they are significant for NEM generation. While integration costs are a valid concern for renewables in general, we do not see them as a significant additional cost item for NEM systems. In particular, the proposed base case integration cost of $8.50/MWh does not seem appropriate for NEM generation. We arrive at this conclusion by considering the individual integration costs, which fall into three buckets:

- **Within hour**. At this time scale, we think that the geographic diversity and large number of small NEM installations (~100,000) smooths the impact profile seen by the CAISO from a system perspective (see Hoff, others) so that in effect there is no increased within-hour volatility from NEM.

- **3-hour ramp**. E3 has performed analysis of the impact of solar installations on system ramp, presented at the stakeholder workshop. E3 found no *net* effect of PV (in some hours more ramp is required, and in some hours there is less need). Therefore, we conclude that the additional procurement costs from existing generation to provide ramp in hours with increased need would be offset by reduced procurement costs in hours with less need.

- **Long-run need for new flexible resources**. This last category is uncertain. While the costs of periods of significant ramp may be offset by periods of reduced ramp, if the high periods require new generators to be built then there would be a cost associated with that increase in ramp overall. The CAISO has discussed the need for increased flexible resources, however, no procurement of new flexible resources has been authorized. Also, there is uncertainty regarding the need overall since new renewables reduce load on existing generation, freeing it up as a flexible resource in the system without the need to build new capacity.

Given that we do not expect NEM installations to impose substantial costs for the intra-hour and 3-hour ramp periods, and given that the impact of NEM on the need for new flexible resources (beyond those required for other new renewable resources) is highly uncertain, we do not plan to include a non-zero integration cost in the base case study. If there is more information on integration costs appropriate for disaggregated

NEM generation we would consider it. We may also add a sensitivity given the uncertainty in the assumptions on the need for new flexible resources, if time and budget allow.

4.3.2 SYSTEM UPGRADE COSTS

[PG&E] To the extent IOUs can estimate the costs of system upgrades, these costs should be included.

[TerraVerde] If system upgrade costs are considered a cost, then the benefits of such as they apply to all ratepayers should be considered.

RESPONSE: At this time there does not appear to be sufficient evidence that NEM DG necessitates system updates, nor is there sufficient data available to estimate system upgrade costs or benefits. Therefore, we don't expect system upgrades to appear in the study as either a cost or benefit.

4.4 Technologies to be Included in Study

[DWEA] 300 small wind turbines up to 55 kW should be included in analysis. DWEA can help get data if necessary.

RESPONSE: We will include wind turbines in the study. We have data on approximately 400.

[SDG&E] Should limit sensitivity testing in study to solar because others are too small to be worth it.

RESPONSE: For completeness, we will include all technologies in the sensitivities. This will add little in terms of time or budget.

4.5 Data to be used in the Study

[DRA] 2012 AMI data should be used as it becomes available.

RESPONSE: Using additional data from 2012 is out of scope given the timing of the study and budget limitations.

[SCE] Should include 2012 data to the max extent possible because NSCR is still coming through.

RESPONSE: The study will be able to project the impact of NSCR. This effect is expected to be small.

[SCE] Should use data from 2012 GRC for avoided costs.

RESPONSE: See discussion on the T&D avoided costs.

[DRA] The public dataset should be made available ASAP since E3 said it is nearly ready.

RESPONSE: What was nearly ready was the dataset we are assembling for analysis. It will take some time to assemble the scrubbed, public dataset.

4.6 Sensitivities

[PG&E] Do sensitivities for all three penetration scenarios: 2011, full CSI, and NEM cap.

RESPONSE: Due to stakeholder interest, we now plan to report the range of sensitivities for all three penetration scenarios.

[SEIA/Joint] Should do sensitivities relevant to R.09-11-014.

[DRA] Should do sensitivities relevant to R.09-11-014: (1)Long-run avoided capacity value at lower value of $117.47/kW-yr (2) location-specific T&D values (3)lower RPS (2012 LTPP RPS calculator or Renewable Energy Market Adjusting Tariff) (4) LOLP on capacity value, like for CAISO, instead of top 250 hours (5) high and low energy costs based on NG and GHG costs

RESPONSE: (1) We do not plan to add a sensitivity on capacity value due to scope and budget limitations. (2) If time and budget allow for the updated T&D avoided cost methodology, we will calculate location-specific T&D values (but do not plan a sensitivity on these values). (3) We will calculate a new RPS premium based on updated data and avoided costs consistent with the rest of the analysis (4) If time and budget allows this will be addressed by use of the ELCC method for capacity value. (5) We will capture through our NG and carbon price sensitivities.

4.6.1 CARBON COSTS

[TerraVerde] Should do a sensitivity on carbon costs.

RESPONSE: We plan to do so.

4.6.2 TIMING OF PEAK DEMAND

[DRA] Should do a sensitivity that considers potential shift in peak demand, which will affect hourly marginal energy prices. Use IOU MC studies or E3 LOLP analysis for CAISO.

RESPONSE: If timing allows we will use the ELCC method for capacity valuation, which would reflect the timing of peak demand, as well as calculating the results under the currently approved method. We do not plan additional sensitivity testing on this.

4.6.3 MARGINAL COSTS

[DRA] Should do a sensitivity on forward-looking marginal cost studies (from most recent GRC or consultation with IOUs.

RESPONSE: This is out of scope/budget.

[DECA] OTC, transmission constraints, etc. will create higher LMPs and capacity prices above marginal costs. This should be captured in an avoided cost sensitivity.

RESPONSE: The resource balance year methodology accounts for OTC retirement in calculating system capacity value. However, the existing avoided cost methodology does not develop capacity value at the level of local capacity resources that would be necessary to perform sensitivity testing on LMP. If we update the avoided cost methodology, we will have this level of specificity but do not plan to do sensitivity tests on levels of congestion, etc.

4.6.4 RATES AND RATE ESCALATION

[SCE] "SCE recommends the inclusion of specific rate structures as part of the sensitivity tests. Most importantly, the steep inclining block rate structures applicable to the California IOUs' residential customers have led to retail rate offsets far above avoided cost levels. Quantification of the differences between current rates, preenergy crisis rate levels, and cost-based rate levels that include fixed cost grid components would not only help inform the NEM discussions but also help inform the open Residential Rate Design Order Initiating Rulemaking (R.12-06-013)."

RESPONSE: This is out of scope in Phase 1 but could possibly be part of Phase 2.

[DRA] Should do a sensitivity on high rate escalation based on commonly available bill savings calculators.

RESPONSE: We plan to do a sensitivity test on rate escalation, but not necessarily on this basis. Rather, the sensitivity will be based on underlying factors.

4.6.5 NATURAL GAS PRICES

[SEIA/Joint] The Joint Parties submit that the 2009 Market Price Referent (MPR) gas cost scenario represents a reasonable High Gas Cost sensitivity. This readily-available forecast represents an average gas price from 2012-2031 which is about 20% above the average price in the E3 forecast and 15% above the 2011 MPR forecast. The much higher 2008 MPR forecast should not be used as the High Case, as it dates from just a few months before the 2008 peak in gas prices, and predates both the full impacts of the recession and the recognition of the significant new supplies of shale gas in North America.

RESPONSE: We agree the 2009 MPR may be a reasonable high gas case and will consider it when we develop the forecasts.

4.6.6 STANDBY CHARGES AND NON-BYPASSABLE VOLUMETRIC CHARGES

[SCE] Should calculate lost standby for residential because would have been developed if not for the prohibition.

[SCE] Lost standby revenue should be the base case

> RESPONSE: Lost standby revenue will be the base case for customers who have applicable standby tariffs. We do not intend to develop hypothetical standby tariffs for residential customers and assume these would have been developed and applied in the absence of NEM. We are not aware of any jurisdictions where residential customers are subject to standby charges, and do not believe it is a certainty that such tariffs would have been applied in California if not for NEM.

[SEIA/Joint] Approve sensitivity of zero standby charges for all NEM customers. See Special Condition 10 of PG&E E-1 and Schedule DR of SDG&E, which exempt residential customers from standby. Maybe should be base case.

> RESPONSE: We will calculate a sensitivity for zero standby charges.

[SDG&E] The "export only" case also wrongly assumes residential customers would not have been subject to demand charges, departing load charges, and/or standby charges if there was no NEM rate schedule. The residential sector had no commercially available self-generation technologies before NEM was established, so there are no alternate self-generation rate schedules that include elements to allow the utility to collect for the services provided and for public purpose programs. It does not follow that such rates would not be developed similar to those in the commercial and industrial sector but-for NEM being put in place.

> RESPONSE: As noted above, we do not believe it is a certainty that such charges would be assessed in the absence of the NEM statute in California. We further note that since we measure the bill credit in the export only case, we will account for public purpose program charges and other volumetric charges that make up part of the full retail rate at which the bill credit is being calculated.

4.6.7 T&D DEFERRAL

[SDG&E] No deferred distribution costs should be base case, sensitivity should be where deferred distribution costs are included.

[PG&E] Base case: include T&D upgrade costs; include Admin costs; include integration costs; exclude T&D deferral; exclude A/S.

> RESPONSE: We will consider running different "packages" of sensitivities representing alternative viewpoints.

4.6.8 RPS

[PG&E] Add sensitivity that assumes REC value identified by CPUC in AB920: 1.8 cents per kWh.

> RESPONSE: We are not planning this as a sensitivity, but a REC value for surplus compensation energy will be included in the base case.

4.7 Reporting and Disaggregation of Results

[SDG&E] Shouldn't bother with "snapshot": "no GHG costs were avoided in 2011 since there was no cap-and-trade program in place, no distribution costs were deferred since distribution planning cycles are 5 years, short-term cost of capacity should be used (a quarter of the long-term capacity value), and actual market electricity costs and actual costs of new renewables should be used for marginal energy costs (will be fairly low due to low natural gas costs, a 20% Renewable Portfolio Standard ("RPS") (instead of 33%), and lower prices for renewables than used in the E3 calculator). This short-term ex-post analysis would seem to take a lot of effort for results that will be disputed by a significant share of the stakeholders regardless of method employed."

> RESPONSE: see below.

[SEIA/Joint] Not sure the 2011 snapshot has value: "question the relevance of a cost / benefit analysis of NEM that is limited to a single year, particularly if the analysis calculates the avoided cost benefits of NEM using short-term market prices solely from 2011, if solar irradiance in 2011 in California departs significantly from a typical meteorological year (TMY), or if loads in 2011 are not typical of the expected future demand for power.

RESPONSE: We think the snapshot is interesting enough to be justified. It provides a number that everyone can understand and that is not affected by forecast uncertainty.

[DRA] Results should be disaggregated by rate class.

RESPONSE: We intend to do this.

[DRA] ZNE or near-ZNE customers are a special case and should be disaggregated for reporting.

RESPONSE: see below.

[TerraVerde] K-12 schools have a unique profile and should be disaggregated for reporting. TerraVerde can help get data.

RESPONSE: Scope and budget do not allow for focusing on specific groups sub-categories of customers.

[DRA] Should report how many customers get to zero bill but are NOT net exporters (due to TOU).

RESPONSE: We agree that this would be an interesting bit of information and will include it.

[CUE] Study should report on: (1) amount of kWh exported, (2) total kWh of generation (3) kWh exported by time of day.

RESPONSE: We will report these values.

[DECA] Give explicit consideration of partial netting where NEM is limited to less than 100% bill offset or certain customer classes can net entire bill while others can't.

RESPONSE: We understand this comment to be directed toward the difference between residential, which is usage based, and commercial, which has demand charges, and therefore won't result in zero bill even when net consumption is zero. We will report separately by rate class.

4.7.1 ALL GENERATION VERSUS EXPORT ONLY

[SDG&E] Shouldn't look at export only because the SPM says the RIM test should be based on "decreased revenues for any periods in which load has been decreased" and load is being decreased from direct offset.

> RESPONSE: Implied is the notion of decreased revenue for any periods in which load has been decreased *as a result of the program being evaluated* and that is the gray area that we are bookending. If the direct offset would have occurred anyway, then it is not correct to measure it as an effect of NEM.

[PG&E] "Neither the Decision, nor AB 2514 call for an analysis of how much generation would have been produced without the current form of NEM. Nor does the decision require completion of an 'export-only' scenario"

> RESPONSE: No, but not prohibited either. It is interesting to know as a bookend and, importantly, allows direct comparison with the 2010 NEM study.

[SDG&E]. Argument for not doing export only: "In other words, the distributed generation would have been installed regardless of the availability of the NEM. The practice in Energy Efficiency if the measure is undertaken in the 'but-for case,' without the incentive, is to reduce the benefits since the benefits would have occurred in any case. The 'net-to-gross ratio' is the measure to reduce benefits in proportion to the percentage of customers that would have undertaken the activity without the incentive. The true 'book-end' would be to assign no benefits to NEM since the utility would receive the same avoided cost benefits without the NEM ratemaking if DG production is unchanged. The 'net-to-gross' reduction in benefits is the 'bookend,' not the 'export only approach.' The 'export only approach' should be eliminated from the NEM Cost Benefit Study." Also, AB2514 says consider all electricity generated, so therefore export only cannot be used.

> RESPONSE: We believe the export only case has merit. First of all, it allows direct comparison to the 2010 report, which will be useful to illustrate the effect changes in retail rates, wholesale electricity prices, etc. have had on the per-kWh cost of NEM. Additionally, we believe that in attempting to measure NEM effects, one must compare the current, post-NEM world to the world as it would have been had there been no NEM. While we do not believe the true level of generation would have

been identical (as implied by the export only case), neither do we believe that *none* of the generation would have occurred in the absence of NEM (as implied by the all generation case). Comparing the bill credit from exported energy under NEM (what ratepayers are paying for the energy) to the avoided cost of the exported energy (how ratepayers value the exported energy) is a reasonable way to evaluate the costs and benefits of the export only case.

[PG&E] "E3 should indicate that in their professional judgment, the 'true' counterfactual result is much closer to the all cost shift estimate, than to the export only bookend. Otherwise the reader may assume that the "cost of NEM" is some average of the two numbers.

RESPONSE: We will attempt to offer context for the bookends.

4.7.2 SPECIFIC RATE IMPACTS

[DRA] Study should address what is the impact to Tier 3-5 rates when 5% cap is reached and who is paying.

[PG&E] Rate shifts should only be applied to Tiers 3-5.

RESPONSE: Our analysis scope does not include evaluating new rates that result from NEM over time, just the total impact on utility revenue and the revenue requirement. Which tiers the revenue requirement is recovered from is beyond the scope of our study.

[PG&E] "...A6 and A10 customers because the TOU periods for those rates change on the half-hour for some TOU periods. PG&E expects to work closely with E3 to ensure optimal estimation of bill savings."

RESPONSE: We plan to model the ½ hour as we have data at this level of granularity. This is an improvement from the 2010 study.

[PG&E] Quantify PPP cost shift.

RESPONSE: We will calculate lost PPP revenues.

4.8 Billing and Admin Costs

[IREC] Despite the fact that SDG&E reported costs much closer to SCE last time, E3 will use the average.

> RESPONSE: In the 2010 study, SDG&E's residential billing costs were $5.96, compared to $3.02 for SCE and $18.31 for PG&E. However, non-residential billing costs for SDG&E were $17.44 per customer, compared to $2.55 for SCE and $18.31 for PG&E. In light of these mixed results, use of an average would appear reasonable.

[IREC] E3 intends to use SCE for the low cost sensitivity, instead of zero like last time.

> RESPONSE: We agree that zero is reasonable for the low-cost sensitivity. This will also maintain consistency with the 2010 report.

[SIA/Joint] Zero incremental billing costs should be the base case.

> RESPONSE: Base case has existing cost, sensitivity is zero; these two cases form reasonable bounds.

4.9 ADDITIONAL ANALYSES

[DECA] What would NEM effects be if output, under projections, were optimized for avoided costs (considering both shape and geographic penetration). Generation profiles will change in response to a migration to TOU rates and maximizing avoided LMPs, so people will, in fact, be optimizing to these parameters.

> RESPONSE: Calculation of this hypothetical is beyond the scope and budget for the project. We are looking at systems as they are currently installed.

[PG&E] Caution must also be taken when considering the assumed reliability value of a MW of customer solar generation relative to a MW of conventional generation. First, rooftop solar tends to be fixed-tilt, south facing, which has lower availability in the late afternoon, hours which coincide with system peak.

Secondly, over time, the peak hours of need will be shifting later in the day, thus reducing the relative capacity value of customer solar.

RESPONSE: This effect will be taken into consideration if timing allows for the ELCC update to the generation capacity avoided cost methodology.

[IREC] AB 2514 requires a Participant test: "quantify the costs and benefits on net energy metering to participants and nonparticipants." E3 will also have all the components to do a TRC test. TRC is the best choice – think about EE: always fails RIM but passes TRC so we do it.

RESPONSE: see below.

[DRA] Study should identify 20-yr NPV separately for participating and non-participating ratepayers.

RESPONSE: The study will identify the costs (higher rates) and benefits (lower bills) of NEM to participants. However, we will not perform a participant test that considers the cost of installing the generator, etc. Therefore we will not have all the components of a TRC test. The study is limited to the revenue (bill credit) and avoided cost benefits of NEM, rather than a complete economic analysis of NEM technologies. Parties may refer to the CSI cost-effectiveness evaluation for a complete analysis of the economics of distributed PV, including the participant cost test and TRC.

[TURN] Study should provide recommendations on how to structure present tariffs to allocate risk and protect ratepayers from high future payments if wholesale generation profiles reduce the avoided cost value.

RESPONSE: Rate design questions are out of scope and budget for Phase 1 in the study, though they may be addressed to some extent in Phase 2.

[PG&E] "PG&E suggests that lost UUT revenues also be included in the analysis, to the extent the IOUs can provide estimates of the impact of NEM on UUT collections. While not a cost shift, lost UUT revenues can be critical to struggling cities.

RESPONSE: Consideration of the effect on municipal taxes and potential responses are beyond the scope and budget for the project.

[SCE] "E3 should make sure not to double count avoided greenhouse gas (GHG) related costs as part of avoided generation/energy costs. Specifically, since the renewables portfolio standard (RPS) adder adds an RPS premium to a percentage (i.e., the relevant RPS target) of the avoided energy costs, an equivalent percentage of the GHG costs should be subtracted from the avoided GHG costs in order to avoid double counting of avoided GHG. It's not clear if E3 considers this potential for double counting in the avoided cost model."

> RESPONSE: Calculation of the Renewable premium accounts for CO2 costs so there is no double counting. E3 does not double count GHG–related costs because E3 calculates the RPS premium net of the value of the emission costs. For example, assume the cost of RPS minus the cost of conventional generation is \$70/MWh. If the emission cost associated with GHG from the conventional generation is \$20/MWh, then E3 uses \$50/MWh (70-20) for calculating the RPS premium. The fact that reducing RPS purchases also reduces GHG savings is captured by using the lower \$50/MWh value.

[SDG&E] The study should provide a measure of the cost of services provided, as required by AB 2514. One simple way to do this is to calculate the costs of the NEM program if the NEM customer paid the full distribution rate, like a DA customer. But SDG&E recognizes that residential rates, as currently structured, lead to larger residential users paying a disproportionate share of customer service, distribution, AB 32, and other public purpose program costs. An alternative would be to quantify the costs utilities incur to provide services, essentially by developing cost-based tariffs for residential customers (they already exist for commercial). Could be done based on GRC Phase 2 filings and provided by utilities.

> RESPONSE: We are in the process of developing a methodology and adding an estimate of the degree to which NEM customers pay their full cost of service that is consistent with AB 2514. This was not in our original study scope. To support this analysis, E3 is currently working on a data request to the utilities of relevant GRC information. We recognize that the methodology was not discussed at the workshop and parties have not had a chance to review it. We will look for appropriate time to evaluate this analysis methodology.

4.10 Natural Gas

[PG&E] Should update gas costs to be current.

> RESPONSE: We will update the natural gas forecast for the study.

[DECA] The NEM study should, at the sensitivity level reflect fuel costs associated with natural gas hedging as well as without it. The cost of hedging strategies should be considered on both the top (high gas prices with hedging costs) and bottom (low gas prices with no hedging costs) gas price sensitivities based on actual hedging costs under Commission approved Time to Expiration Value at Risk ("TEVAR") methodology.

> RESPONSE: We believe that we are appropriately capturing the hedge value by using the natural gas futures prices currently available using the MPR methodology. At the futures prices, the gas price could be fixed. Our understanding is that the TEVAR metric measures value at risk due to volatility in spot natural gas purchases. Our approach of assuming all forward purchases would leave no exposure to spot market volatility.

4.11 Adoption Forecasts

[DRA] Should leverage CEC predictive model, prior LDPV study, and Itron's technology adoption analysis for adoption forecasts.

> RESPONSE: We will consider these sources in creating our forecasts.

4.12 Customer Demographics

[DRA] Income data should be from within 1 year of when a customer submitted the NEM application.

> RESPONSE: While this would be nice, we are not aware of a source for this information. The best data source we know of is the most recent census data, which provides a good measurement of demographics by census tract.

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5 Links for Reference

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