Phase II of A.13-08-003 et al - GHG Applications

Questions for Discussion – 7/3/2014

Based on the IOUs' joint proposal and briefs, the Energy Division identified follow-up questions for clarification and discussion.

Indirect Cost Forecasts

1. **SCE and SDG&E**: Both utilities propose to forecast indirect GHG volumes by multiplying estimated market purchases by ARB's default emission factor for unspecified power (0.428 MT/MWh). To convert indirect emissions into costs, SCE and SDG&E propose that they should have the ability to choose between using either a proxy price or a confidential price.[1] <u>What is the rationale for using a proxy price when forecasting direct emissions, but to have the option to use a different, confidential price forecast when forecasting indirect emissions?</u>

2. **PG&E:** Can PG&E clarify how it proposes to estimate indirect emissions volumes? PG&E states that it will "estimate indirect GHG emissions volumes from generation resources included in its annual ERRA forecast."[2] <u>Is PG&E proposing the same methodology to estimate indirect emissions volumes as SDG&E and SCE?</u>

   PG&E Response:

   a. PG&E uses a more complex methodology to forecast indirect GHG emissions than SDG&E or SCE that varies depending on the category of generation resource in the portfolio.
   b. PG&E's forecast of Indirect GHG volumes include more than just market energy purchases. PG&E also forecasts indirect GHG volumes for contracts with energy price formulas tied to market prices. This includes energy payment formulas: 1) based on a market energy price or a market heat rate, and 2) with a GHG allowance price in the formula.
   c. For most contracts with energy price formulas tied to a market price, PG&E forecasts indirect GHG emissions volumes using the method SDG&E and SCE propose to use for market purchases (i.e. using ARB's default emission factor of 0.428 MT/MWh.
   d. For some contracts that include a GHG allowance price in the energy payment formula, the methodology to forecast indirect GHG emissions is contract-specific, based on provisions specified in the contract.
   e. For market energy purchases, PG&E forecasts indirect GHG emissions using marginal GHG-emission rate assumptions from the GHG calculator developed for the CPUC by Energy and Environmental Economics (E3). Rather than use a single emission factor of 0.428 MT/MWh, PG&E uses four time-of-delivery (TOD) specific factors that range between 0.38 and 0.42 MT/MWh.

Reconciliation

1. **Actual Direct Costs - All IOUs**: The revised proposal and joint brief have ambiguous statements about how the utilities plan to calculate actual direct emissions and costs. The utilities state that "actual direct GHG emissions should be calculated on an annual basis and be consistent with

[1] Revised Joint IOU Proposal, p. 8.
[2] Id. at 6.

ARB regulations for measuring GHG emissions."[3] The utilities elsewhere discuss that they will record monthly GHG costs in their ERRA accounts based on actual direct emission volumes multiplied by the weighted average cost of compliance instruments purchased (of the current year's vintage). Is it correct to interpret that the large utilities, at least, propose that annual GHG costs reported in the reconciliation applications would be sum of these monthly GHG costs recorded to ERRA?

PG&E Response:
Yes, PG&E's annual reconciliation of actual direct GHG costs matches the sum of monthly direct GHG costs included in the ERRA compliance filing for the same year.

2. **Estimated Actual Indirect Costs – All IOUs**: The utilities state that the method to calculate indirect GHG emissions should be consistent with the method to forecast indirect GHG costs, but the method does not need to be consistent across utilities. What is the rationale to justify using different methods to estimate indirect GHG costs? The utilities asked the Commission to decide which price should be used to estimate indirect GHG costs. Are the utilities proposing that they should be allowed to estimate indirect emissions via different methodologies, even though the utilities recommend that the Commission should establish a fixed method to calculate cost of indirect emissions (e.g. ICE vs CAISO vs ARB auction prices)?

   PG&E Response:
   For the purpose of a GHG cost reconciliation, PG&E proposed using a simplified method to calculate an updated estimate of indirect GHG emissions that is consistent with SDG&E and SCE's approach, i.e use CARB's default emission factor for unspecified sources (0.428 MT/MWh) and apply it to recorded generation volumes for all applicable generation resources (market energy purchases as well as contracts with energy payments tied to a market power price, a market heat rate or GHG allowance price).

3. **Revised Current Cost Forecast – All IOUs**: When the utilities discuss their disagreement about "whether a revised forecast of current year GHG costs should be part of the GHG cost reconciliation in the GHG application,"[4] it is unclear to which year "current year" refers. Could the utilities clarify this issue by way of example?

   PG&E Response:
   Current year refers to the calendar year in which the cost reconciliation is filed as part of the GHG Revenue Return and Reconciliation Application. PG&E's position is that the GHG cost reconciliation should be an annual process and should only include a reconciliation of the GHG cost forecast for the prior calendar year. For example, on May 30, 2014 PG&E included a reconciliation of 2013 GHG costs in the filing. A reconciliation of 2014 GHG costs would not be filed until May 2015.

4. **Revised Forecast of GHG Revenues – SDG&E**: Similar to the question above, can SDG&E clarify its proposal to only true-up the prior year of revenue and not to reforecast current year revenue?[5]

[3] Id. at 12.
[4] Id. at 12.
[5] Id. at 13.

Confidentiality

1. Why is "Total forecast GHG costs or revenue requirements using proxy price" listed as Confidential in the GHG Information Matrix?[6]

   PG&E Response:
   PG&E is checking with the other IOUs to confirm the reason for marking "Total forecast GHG costs or revenue requirements using proxy price" as confidential in the Confidentiality Matrix, and will respond in more detail next week. In particular, PG&E will be checking to determine if all the utilities can agree that the designation can be "public" if the proxy price is public.

2. The utilities ask the Commission for authority to make a single notification to ARB upon disclosing confidential information during PRG meetings.[7] However, ARB's regulations seem to require that utilities report these disclosures to ARB within 10 days of making the disclosure and that utilities must cite to Commission authority to make such disclosures. <u>Do the utilities believe the Commission has the ability to authorize the utilities to only make a single such notification to ARB rather than a notification each time an authorized disclosure is made?</u>

   PG&E Response:
   No. The Commission does not have the authority enforce notification that is inconsistent with ARB regulation.

[6] Id. at A-4.
[7] Joint Utility Opening Brief at 5-6/