EB-2024-0111

Current Energy Group Responses to CCC Interrogatories on Exhibit M2

October 18, 2024

M2-CCC-1

Ref: Ex. M2/pp.2-3

Questions:

a) Please advise whether CEG is suggesting that all of its recommendations be implemented for Enbridge Gas's 2025-2028 rate framework.

b) Please provide a ranking of its recommendations in terms of what it believes are most important to be implemented for Enbridge Gas's 2025-2028 rate framework.

Response:

(a) Not necessarily. The purpose of CEG's report was to identify adjustments to the proposed incentive rate-setting mechanism for Enbridge Gas aimed at improving capital cost containment and mitigating financial risks to customers associated with the energy transition. CEG recognizes that making modifications to a rate-setting process takes thoughtful consideration. CEG also recognizes the regulatory principle of gradualism and that the OEB may wish to stagger some of the changes. CEG recommends the Commission prioritize the adoption of differentiated ROE and customer class revenue decoupling. CEG recommends prioritizing these recommendations as a first step for aligning the utility's financial interests with their customers' interests.

(b) Please see a discussion of subpart (a) to better understand why CEG recommends prioritizing differentiated ROE and customer class revenue decoupling. CEG's ranking:

1. Differentiated ROE
2. Revenue decoupling
3. Remove bias against CIACs
4. IRPA Shared Savings Mechanism
5. Gas supply risk.

M2-CCC-2

Ref: Ex. M2/pp.8-12

Questions:

a) Please advise whether the recommended differentiated ROE approach has been implemented in any other jurisdictions. If so, please provide references to the relevant policy documents, decisions, etc.

b) How does CEG recommend that the OEB define growth assets/projects and separate those projects from all other projects in order to operationalize the approach.

c) In terms of maintaining a fair return for Enbridge Gas, please advise which of the following approaches form part of CEG's proposal for differentiated ROE (and provide any further commentary on the benefits/drawbacks of each sub-option):

i. Reduce ROE% on growth assets and increase ROE% on non-growth assets in a manner that, on a forecast basis, the overall ROE% applied to rate base is unchanged from the current level.

ii. Reduce ROE% on growth assets with no increase to ROE% on non- growth assets but a reduction to risk through more comprehensive decoupling of revenues from throughput (or other methods of de-risking).

iii. Reduce ROE% on growth assets with no increase to ROE% on non- growth assets but an allowance to earn a return on pipeline repair investments that are historically treated as operational expenses.

iv. Any other approaches or combination of approaches that are not listed above.

d) With respect to the recommendation to "allow Enbridge Gas to capitalize certain operating and maintenance expenses related to pipeline repair", please further describe what repair-related operating expenses would fall in this category. In addition, please further explain how this capitalization approach would be operationalized (e.g., is the intent that a pipeline repair operating expense would form part of rate base and be depreciated over the same period of time as the underlying asset being repaired).

Response:

(a) Yes.

a. The Hawaii Public Utilities Commission is authorized to consider the establishment of differentiated authorized rates of return on common equity to encourage increased utility investments in transmission and distribution infrastructure, and discourage an electric utility investment in fossil fuel electric generation plants. The differentiated authorized rates of return are statutorily authorized as a mechanism to incentivize grid modernization and disincentivize fossil generation, respectively.[1]

b. The Federal Energy Regulatory Commission allows incentive rate treatment for certain types of transmission and cybersecurity investments.[2] For example, FERC conditionally approved a 50-basis point ROE adder for Orange and Rockland Utilities' transmission facilities that participated in a Regional Transmission Organization.[3]

(b) One option would be to characterize each investment on whether its primary purpose is system expansion or reliability. Alternatively, an asset could be classified as a growth asset if it *increases* capacity to connect new customers or allows for expanded consumption from existing customers (e.g., new pipes or larger pipes). Pre-existing Enbridge asset classifications may be sufficient.

(c) The appropriate structure depends on the specific situation of the utility. For instance, the appropriate ROE structure for a dual-fuel utility may be different than a gas-only utility. Similarly, a gas-only utility that operates under a performance-based framework and has the opportunity to achieve financial incentives through meeting certain objectives is differently situated than a gas-only utility that does not operate under a performance-based framework. As alluded to in (c)(ii), it is important to consider what other risks and risk mitigation measures are in place for a specific utility.

Option (i). CEG has offered Option (i) as a relatively straightforward way to implement differentiated ROE in the near term in a manner that would hold the utility indifferent from an overall authorized ROE percentage perspective. The animating principle is that there is value in helping to re-orient capital investments in a manner that limits system expansion and attendant stranded asset risks with system growth in an era of flat or declining demand. One drawback to Option (i) is that elevating the ROE percentage for non-growth investments will increase the incentive to invest in the higher-earning ROE percentage class, which may or may not be desired.

Option (ii). Concerning Option (ii), CEG views a reduction in authorized ROE percentage for growth assets with no corresponding increase in authorized ROE percentage for non-growth assets but a corresponding reduction in risks through elements such as a comprehensive revenue decoupling as a preferred approach. There may be an opportunity to further balance the overall framework by integrating additional earnings opportunities as outlined in Option (iii). Option (ii) approach could comport with a fair return standard, but it is outside the scope of CEG's evidence to provide an opinion on

[1] HI Rev Stat § 269-6e(4) (2023). Available at: https://law.justia.com/codes/hawaii/title-15/chapter-269/section-269-6/.

[2] https://www.ferc.gov/incentives

[3] FERC. Order on Tariff Filing, Establishing Paper Hearing Procedures, and Establishing Hearing and Settlement Judge Proceedings. Docket No. ER-24-1614-000. Issued May 24, 2024. Available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240524-3049&optimized=false. P. 2.

whether specific percentage changes and specific risk reduction levels would comport with the standard.

Option (iii). Regarding Option (iii), it shares the same core features as Option (ii) with a reduced authorized ROE percentage for growth assets and an unchanged authorized ROE percentage for non-growth assets but an allowance to earn a return on pipeline repair investments that are historically treated as operational expenses. The benefit to Option (iii) is that the financial incentives extended to the utility reflect the relative risk profile of different categories of investments and is better aligned with customer interests as a result. There may be some amount of distortive effect as a result of the new earning opportunity for pipeline repair but, on balance, this trade-off is likely appropriate provided there is sufficient oversight. One would like to avoid a situation where pipeline repairs are accelerated and preferred over alternative solutions on account of the earnings opportunity alone. As with Option (ii) above, CEG takes no position on how any specific detailed implementation of Option (iii) may be viewed through a fair return standard.

CEG Preferred Approach – Hybrid of Option (ii) and Option (iii)
CEG prefers a combination of Option (ii) and Option (iii) above. This Hybrid Option (iv) reduces the authorized ROE percentage for growth assets. From a fair return perspective, this reduction in authorized ROE percentage is balanced by a reduction in risk from a comprehensive revenue decoupling mechanism and the opportunity to earn a return on pipeline repair investments that would have historically been considered operational expenses. This Hybrid Option (iv) extends financial incentives to the utility that prefers maintenance and repair of the existing network rather than continued system expansion (along with its attendant stranded asset risk). It helps to mitigate downside financial risk for the Company through a comprehensive revenue decoupling mechanism even as it suggests a shift in categorical investments away from continued system expansion, and allows earnings opportunities related to pipeline repair, reflecting the importance of maintaining a safe and reliable system overall.

Finally, the OEB may consider performance incentives for meeting OEB and province objectives as an opportunity for the utility. In Puget Sound Energy's 2024 General Rate Case, CEG Partner, Mr. Cebulko, recommended a reduced ROE for growth-related investments. Mr. Cebulko also proposed an upside-only performance incentive that would financially reward Puget Sound Energy for achieving beyond its electrification program goals.

(d) CEG Partners McDonnell and Cebulko are not accounting experts nor engineers. Mr. McDonnell and Mr. Cebulko are generally familiar with FERC Uniform System of Accounts. Generally speaking, CEG is referring to certain expenditures in Accounts 887 Maintenance of Mains and 892 Maintenance of Services.[4] Within those two accounts, are items related to pipeline repair including "Trenching, backfilling, and breaking and restoring pavement in connection with the installation of leak or reinforcing clamps," "Repairing leaking joints," and "Repairing broken mains."

[4] https://www.ecfr.gov/current/title-18/chapter-I/subchapter-F/part-201

Yes, it is CEG's recommendations that the pipeline repair operating expense would form part of rate base and be depreciated. However, because pipeline repairs typically have a shorter service life than pipeline replacement, CEG would recommend that the depreciation for the repair reflect its shorter life. A shorter depreciation schedule may be advantageous as it may better match the costs of the repair with the customers who incur the benefits, thereby reducing intergenerational inequities. If demand for natural gas declines significantly due to the energy transition, projects with longer services lives have a greater chance of being underutilized or stranded.

M2-CCC-3

Ref: Ex. M2/pp.12-14

Questions:

a) Please advise whether CEG's proposed "revenue per customer class" decoupling approach results in a true-up of revenues for both changes in average use per customer and customer count (but not weather). As part of the response, please explain how variances in demand/throughput relative to forecast caused by changes in weather relative to forecast is addressed in the proposed methodology.

b) Please provide a numerical example that highlights the operation of the revenue per customer class decoupling approach. As part of the response, please highlight how the utility retains weather risk.

c) Please advise whether the recommended comprehensive revenue decoupling approach (i.e., full true up of revenues related to both volumes per customer and customer count) has been implemented in any other jurisdictions. If so, please provide references to the relevant policy documents, decisions, etc.

Response:

a/b) CEG confirms that the "revenue per customer class" decoupling approach discussed in the evidence is intended to true up actual revenues for changes in sales volume per customer class (but not weather) and customer count per class. The variances in sales volume would be 'normalized' to account for weather changes to ensure the utility still holds weather-related risk. This approach to weather normalization could operate akin to the approach directed by the OEB in the average usage per customer variance account. The difference is that rather than applying weather risk and weather normalization to the average use per customer, the CEG proposed revenue decoupling approach would seek to true up actual revenues collected to authorized revenues due to changes to total sales volume per customer class, which would include sales declines due to customer departures – not just changes to average use per customer.

Note that there are other mechanisms that could be used to achieve the same goal of ensuing that the utility is made largely indifferent to customer additions or reductions, as discussed below.

A hypothetical example is provided below to help illustrate the operation of a revenue per customer class decoupling approach.

Revenue Decoupling per Customer Class – Hypothetical Example	
Class	Residential
Allowed Revenues[5]	$2,000,000
Collected Revenues[6]	$1,500,000
Variance	$500,000
Weather Normalization Adjustment	($100,000)
Weather-Normalized Revenue Variance	$400,000

In the above hypothetical example, allowed revenues were $2,000,000 for the residential customer class. The utility under-collected revenues at a total of $1,500,000. Of the $500,000 variance, $100,000 of the loss in sales volume was attributable to weather. Accordingly, after a weather adjustment, the revenue variance to be trued up for the residential customer class is $400,000. This $400,000 would be collected via a minor increase in residential customer bills over a predetermined true-up period. This example would also work in the opposite direction to result in a negative variance if the collected revenues are higher than the allowed revenues. With a modest adjustment, the utility could be allowed to earn a percent of said revenue to account for incremental O&M costs of serving more customers.

The above hypothetical approach is comprehensive in its design, ensuring that the utility does not have an inherent structural preference for adding new customers over the plan period and would remain indifferent to customer departures as well. Moreover, the comprehensive per customer class revenue decoupling mechanism ensures that the utility is indifferent to reductions in customer usage. The Revenue Decoupling per Customer Class mechanism would be effectuated through a Revenue Balancing Account that would replace the existing Average Use per Customer Variance Account. Overall, it reflects a comprehensive approach to realigning structural financial incentives for the utility in an era of energy transition. In other words, the utility could not earn more revenue from increasing customer counts nor lose revenue from decreasing customer counts vis-à-vis the allowed revenues assumed in the test year.

[5] "Allowed Revenues" would be established during the test year on a per customer class basis. Allowed Revenues could be escalated year over year pursuant to the same I-X formula applied to the Price Cap mechanism.
[6] "Collected Revenues" would reflect actual revenues collected per customer class during the true-up interval, which could be monthly, quarterly, or annually.

In the alternative, should the OEB wish to preserve the existing Average Use per Customer Variance Account or prefer a different approach for other reasons, the core objectives of the Revenue Decoupling per Customer Class mechanism could be achieved through the creation of a Customer Count Variance Account. Under a Customer Count Variance Account approach, all or a portion of the revenue associated with net customer additions would be offset via the variance account. This customer count true up could be calculated against the customer counts for the test period. The variance account would record the revenue impact of the difference between the annual customer counts and those embedded in base rates for each of the general service rate classes.[7] The true-up likely should be offset by the incremental costs or savings from adding or subtracting customers of that class (i.e. the incremental O&M cost of serving an additional customer in the relevant rate class).[8] A hypothetical example is shown below.

Customer Count Variance Account – Hypothetical Example	
Class	Residential
Net customer additions vs. test year[9]	10,000
Average revenue per customer[10]	$600
Average incremental cost per customer[11]	$100
Variance	-$5,000,000

This example would also work in the opposite direction to result in a positive variance if there are net customer losses. This example calculates the variance based on average revenue per customer. However, it may be possible for the utility to calculate the variance with more specificity using the actual billing data for customers that are connected to the system and those that exit the system. We do not know whether that is possible with the utility's information systems. Either option would be an improvement on the current approach.

[7] For example, a simplified calculation would be: [variance in customer counts] x [average revenue per customer], with the assumption that each customer connecting to the system or leaving the system does so halfway through the year.

[8] The calculation would be [variance in customer counts] x [average incremental costs per customer].

[9] This example assumes that 20,000 customers were connected throughout the current year, with each customer being connected to the system for an average of 50% of the year. In year 2, all of the customer additions from year 1 would be included plus 50% of the customer additions in year 2.

[10] This would be a weather-normalized figure to ensure that the utility maintains the weather-related risk. However, a non-weather-normalized figure could be used without negatively impacting the efficacy of this approach.

[11] The incremental cost per customer per rate class would be based on the test year and adjusted by I – X for each future year. Although this is likely the simplest and best approach, the incremental cost per customer could alternatively be held static for each of the future years or set each year based on actuals.

This variance account could be designed in a number of different ways and the design would depend on how much of the revenue from incremental customers it would be appropriate for utility to retain. The above example reflects a decision that the utility should be allowed to retain enough incremental revenue from incremental customers to cover incremental costs associated with those customers (and vice versa with respect to customer defections). But if the regulator felt it was appropriate for the utility to retain all of the revenue from incremental customers this could be achieved by recording and truing up the revenue impact of the difference between the annual customer counts and forecast customer counts. One ancillary benefit of establishing a customer count forecast is that it would illuminate the utility's assumptions and projections related to customer growth or defections.

As this discussion shows, there are a number of ways to make the utility indifferent to customer additions and customer defections. Our main point is that this is a very important step to take in light of the energy transition for the reasons outlined in our report. Any of the above options would be acceptable because they would give the utility the appropriate incentives. The Revenue Decoupling Per Customer Class option is the most comprehensive whereas the Customer Count Variance Account would be the simplest to add on to the existing framework.

c) The CEG recommended comprehensive revenue decoupling mechanism shares similarities with the Hawaiian Electric Companies' revenue decoupling mechanism.

Reconciling Actual Revenue with Authorized Revenue

Revenue Balancing Accounts (RBAs) record the monthly differences between target revenues and the adjusted recorded electric sales revenues. The RBA applies monthly interest, equal to the annual rate for short-term debt from the cost of capital in each HECO Company's last base rate case, to the simple average of the beginning and ending balances each month in the RBA. In effect, the RBA applies one-twelfth of the rate each month. Finally, the RBA provides for collection or return of the calendar year-end balances in the RBA over the subsequent year period. The target revenue is the most recent Authorized Base Revenue or the re-determined Authorized Base Revenue calculated.

The Company must file with the Commission a statement of the previous year-end balance in each RBA sub-account and the Authorized Base Revenue level for the current calendar year with supporting calculations. An amortization of the year-end balance in the RBA sub-accounts are recovered through the per-kWh RBA rate adjustments.[12]

[12] *See* Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, Revised Sheet No. 92, Effective October 1, 2023, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf.

M2-CCC-4

Ref: Ex. M2/pp.14-16

Questions:

a) Please confirm that CEG's recommendation is for the "calibrated ECM approach with CAPEX efficiency sharing."

b) CEG states that, "a special type of ECM that is applied separately to capex and opex and carefully calibrated to equalize cost containment incentive between them can help address capex bias across a multitude of utility expenditures."

c) Please explain how this would be operationalized for Enbridge Gas's 2025-2028 IRM term. As part of the response, please provide a numerical example for the operation of each the EBSS and CESS.

Response:

a) CEG can confirm that its recommendation is to examine a calibrated ECM approach with CAPEX efficiency sharing.
b) Yes.
c) The development of a calibrated ECM approach with CAPEX efficiency sharing can be relatively complex and more study and stakeholder input is likely necessary before successful implementation and operationalization for Enbridge Gas's IRM is possible. CEG recommends operationalizing an ECM for Enbridge Gas's 2025-2028 IRM may be suboptimal without further study and development and therefore offers that the development of an ECM should be studied further with findings to be shared in advance of Enbridge Gas's next plan period.

M2-CCC-5

Ref: Ex. M2/pp.16-17

Questions:

a) Is CEG's recommendation to allow Enbridge Gas to earn margin on CIACs subject to the outcome of the hearing to consider the appropriate revenue horizon? If so, what finding is CEG recommending that the OEB make in the current proceeding. If not, please explain.

b) With respect to the applicability, quantum and accounting for margin payable on CIACs, please provide CEG's views on the following:
   i. Are the aggregated CIAC payments received equivalent to a rate base amount that is accounted for outside of rate base?
   ii. When does the CIAC payment begin earning a return (i.e., at the time of payment, at the time the relevant asset goes into service, etc.)?
   iii. Is a return paid on the entire CIAC payment in a single year? Alternatively, is the CIAC payment notionally depreciated over an equivalent amount of time as would be applied if the asset was in rate base and returns are paid annually on the undepreciated portion of the CIAC payment?
   iv. Does the CIAC payment attract only a margin payment (i.e., no debt recovery is applied)?
   v. Does a CIAC payment attract the OEB-approved ROE on the deemed equity portion of that payment as if the asset were in rate base? Or is there some other approach that CEG is recommending?
   vi. Do all CIACs payments attract a margin payment? Or is it some subset of CIAC payments?

c) Please advise whether it is CEG's proposal that the margin paid on CIACs is recovered from all ratepayers (i.e., equivalent to the recovery of return on the equity portion of rate base).

d) Please provide CEG's views on applying the margin payment within the CIAC payment (i.e., the connecting customer pays the connection costs plus margin). As part of this response, please discuss CEG's views on the incentives/disincentives that would be applicable to connecting customers and the utility under this approach.

Response:

a) There are multiple paths to the same outcome. CEG's recommendation is to eliminate, or at least reduce, the incentive for Enbridge to include connection assets in rate base, by allowing the Company to earn a margin on CIACs. However, earning a margin on CIAC is contingent upon lowering the generic revenue horizon or if the Company applies a lower revenue horizon for a customer-specific reason. At this time, the OEB could adopt the concept in principle and instruct parties to prepare specific recommendations on the appropriate revenue horizon.

b) See answers below.

i. Not necessarily, as that level of precision is unnecessary and could be administratively burdensome. Moreover, there is too much uncertainty about actual uptake. The OEB should assume that it may need to iterate on the appropriate margin and revenue horizon using actual data and results to inform its decision-making.
ii. At the equivalent time in which the Company would begin earning a return on connection costs in rate base. Alternatively, if the OEB finds that the ability to earn margin on the CIAC is less than the potential earnings from rate basing the connection costs, then it may be appropriate for the OEB to allow recovery on a more immediate basis, such as the time of payment, so as to further reduce the incentive to rate base connection costs.
iii. CEG recommends that the return CIAC payment would not be paid out in its entirety over a single year but that the CIAC payment be notionally depreciated over an equivalent amount of time as would be applied if the asset was in rate base and returns are paid annually on the undepreciated portion of the CIAC payment.
iv. Yes, the CIAC payment, as proposed, would only attract a margin payment (i.e., no debt recovery is applied).
v. A CIAC payment could attract the OEB-approved ROE on the deemed equity portion of that payment as if the asset were in rate base. In the alternative, a reduced rate of return (i.e., 5%) could be applied.
vi. Only those CIAC payments that result from the utility's application of a reduced default revenue horizon would be eligible for a margin payment.

c) It is CEG's recommendation that the margin payment be recovered from the connecting customer.
d) CEG supports an approach that would require the connecting customer to pay connection costs plus the attendant margin to the utility. This approach helps expose the connecting customer to the true cost of connection under the framework, i.e., CIAC plus utility margin. Such a price signal can help inform the connecting customers' behavior and, in certain cases, lead to more economically efficient decisions.

M2-CCC-6

Ref: Ex. M2/pp.18-19

Questions:

a) Please provide CEG's view on the level of control that Enbridge Gas has on natural gas commodity prices. As part of the response, please explain whether CEG believes that market factors (supply, demand, etc.) or Enbridge Gas's procurement decisions predominately impact the price paid for the natural gas commodity.

Response:

a) Natural gas is a global commodity, and its price is dictated by numerous factors that are beyond the control of Enbridge Gas. Those factors include the levels of natural gas production, customer demand, local, national, and global economic conditions, seasonality, weather, energy policy, and market actions.

   Although the Company does not have control over the wholesale price of natural gas, Enbridge Gas's procurement decisions do have an impact on the costs it passes onto its customers. Enbridge Gas has significant decision-making authority over the amount of demand-side resources it procures. Enbridge Gas also has significant decision-making authority over its supply-side resource procurement strategy, including its use of physical and financial hedges, the lengths of its contracts, when it makes purchases and contracts, and from which supply basins it purchases gas. In its 2023 Annual Updated Gas Supply Plan, Enbridge identifies its supply sources to include the WCSB, Dawn, Chicago, Niagara, U.S. Midcontinent, Ontario Production and the Appalachian Basin.[13]

   As explained in CEG's technical report, because the cost of gas supply is 100% passed onto customers (who have no control over Enbridge's procurement practices) the Company is incentivized to mitigate its risks rather than the manage the costs incurred by customers. A risk-sharing mechanism that exposes Enbridge, even with a relatively limited amount of risk exposure, would better align Enbridge's financial incentives with customer interests.

[13] Page 20.

M2-CCC-7

Ref: Ex. M2/pp.18-19

Questions:

Please describe the findings/orders that CEG is recommending that the OEB make in the current proceeding with respect to the treatment of the IRPAs. As part of the response, please discuss in more detail the proposed allowance for and treatment of electricity IRPAs.

Response:

CEG took its inspiration for the shared savings mechanism from New York state, which allows the electric and gas utilities to earn a share of the benefits of a non-pipeline (NPA) or non-wires alternative (NWA) project.[14] The New York Public Service Commission calculates a project's net benefits using a societal cost test. The electric and gas utilities first establish an "Initial Incentive" equal to 30% of the present value of net benefits ("Initial Net Benefits"), i.e., the present value of net benefits projected at the time the Companies have either entered into contracts or when there is reasonable certainty on the price of the project portfolio. Once the project has been fully implemented, the utility again calculates the difference between the NPA or NWA project cost, which equals the initial forecasts costs of the project less the actual cost. The final incentive may equal the sum of the initial incentive and 50% of the difference in the project cost. The final incentive is subject to a floor of $0 and a cap of 50% of the initial net benefits.

CEG believes the New York model is well-structured and appropriately incentivizes the utility to manage costs. However, due to its complexity, CEG initially recommended that the OEB consider a shared savings mechanism that was focused on allowing the utility to earn up to 30% of the net benefits of the IRPA.

[14] 19-E-0378, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, With Modifications. Appendix HH.