REF: Exhibit A, Tab 3, Appendix A, pg. 1, line 1 and Exhibit D, Tab 1, pg. 1-2

Preamble: Paragraph 4 and 5 in the second reference account for $9.6M of the $18.7M the company is seeking recovery. We would like to understand the other contributing factors to the other half and the escalation from $8.1M in 2022.

1) Please provide and quantify the other significant contributing factors to the remaining $9.1M of recovery.
    a) Please provide a comparison of this year's contributing factors to those in 2022.

REF: Exhibit A, Tab 3, Appendix A, pg. 1, line 2 and Exhibit D, Tab 1, pg. 3-4

Preamble: In the second reference, EGI evidence states: *Transactional services optimization in the Enbridge Gas rate zones is higher than what has been included in rates due to changing market dynamics. The majority of this increase results from the increase in the Dawn-Waddington spread. This spread is influenced by the lack of pipeline infrastructure serving US Northeast markets.*

We would like to understand better the breakdown of the components of the transactional services revenues.

2) Please populate the following table for both 2022 and 2023 for the EGD Zone:

Month	Storage-based Revenue	Transportation-based Revenue	Transportation to Waddington	Other Transportation

    a) Please describe the other significant contributions to revenue for 2023 with a comparison to 2022

REF: Exhibit A, Tab 3, Appendix A, lines 18 & 23 and Exhibit E, Tab 1, pg. 6-11

3) Please populate the same table shown in 2 for 2022 and 2023 for the UGL Zone.
    a) Please compare and provide the difference between EGD and UGL results for 2023 for storage & transportation-based revenue.
    b) How is revenue treated for non-peak storage sold short-term including additional cycling rights?

REF: Exhibit B, Tab 2, Schedule 4, pg. 1

4) Please provide the content of footnote (1).
    a) If not included in the response to the footnote, please describe the sources of Other Income in Line 11.
    b) Please explain the debit vs. credit between 2022 and 2023.

REF: Exhibit B, Tab 3, Schedule 1, pg. 2, line 1

Preamble: We would like to understand better the components of Compensation and Benefits and the escalation in 2023.

5) Please provide a breakdown of the components of Line 1 ensuring that salaries, performance increases, severances, benefits and other significant categories are disaggregated.
    a) Please explain the reasons for the 2023 escalation of the components.

REF: Exhibit B, Tab 3, Schedule 1, pg.3 & 5, Table 2

Preamble: We would like to understand more about the overhead capitalization impact including allocations to Corporate.

6) Please provide a comprehensive breakdown of all projects, initiatives and other categories to which allocations were made to CSS. Please quantify:
    a) the rate used for both CSS and non-CSS
    b) the total FTE's in each of the departments provided in paragraph 6
    c) other factors to justify theses allocations

7) Please provide the answers to question 6 for 2022.

8) Please provide the contents for Table 2 for each of the years 2019 to 2022.

REF: Exhibit B, Tab 3, Schedule 2, pg. 7

9) Please provide the meter change units for each of 2019 to 2023 for each rate zone.

REF: Exhibit B, Tab 3, Schedule 1, pg. 4 and

EB-2024-0111 Exhibit 1, Tab 13, Schedule 2, pg. 6

Preamble: In the second reference, EGI evidence states: *Prior to 2019, EGD did not allocate any of its materials and supplies inventory to unregulated storage operations, which continued through the deferred rebasing term for the EGD rate zone.*

10) Using the proposed approach to the rectification of this practice in the Phase 2 evidence, please provide the annual amount of costs that would have been allocated away from the utility to the non-utility storage for each year in the deferred rebasing period.

REF: Exhibit C, Tab 1, pg. 8

Preamble: EGI evidence states: *On a cumulative basis, this policy alignment resulted in a gross revenue requirement decrease, or sufficiency of $24.339 million, however, the forecast balance approved for clearance as part of the Rebasing Decision was a gross sufficiency of $36.494million, resulting in a variance in the deficiency balance of $12.155 million that is proposed for disposition as part of this 2023 ESM Proceeding.*

We would like to understand the appropriateness of this proposal.

11) Please provide the specific reference to the rebasing decision that EGI is relying upon for this proposed recovery.
    a) How much incremental capital was added to ratebase through this policy alignment over the deferred rebasing period.
    b) What is the revenue requirement associated with this incremental capital for each year in the period from 2024 to 2028.

REF: Exhibit C, Tab 1, pg. 14-15 and Table 1 & 2

Preamble: EGI evidence states: *The balance in the 2023 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of $3.081 million, plus forecast interest of $0.247 million, for a total debit of $3.328. This amount is attributable to incremental Enbridge Gas staff salaries including expenses for IRP related work performed in 2023, the implementation of Integrated Resource Plan Alternatives (IRPA(s)) to defer a project in Kingston and non-labour costs such as consulting and legal costs. The OEB in its IRP Decision approved "incremental IRP* *administrative costs required to meet the increased workload related to IRP"1 … 'be treated as expenses and recorded in this account [operating costs deferral account]."2*

12) Please provide a yearly breakdown of the costs allocated using the categories described in the above evidence reference.
    a) Specific to the non-labour costs, please provide:
        i) The yearly internal and external costs allocated
        ii) The specific engagements of outside agencies and their tasks and deliverables

13) Using the role descriptions in Table 2, from timesheets or other documentation, the percentage allocation to IRP in each of 2021, 2022 and 2023.
    a) Please provide the total amounts associated with the salaries for the above years
    b) Please provide the salary actuals in O&M for DOE staff for the above years

REF: Exhibit C, Tab 1, pg. 19-20

Preamble: EGI evidence states: *The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement. Enbridge Gas determined that this project could be deferred by implementing a supply side IRP alternative in the form of CNG beginning in 2022.[6] Without the CNG injection, the Kingston system was anticipated to fall below its minimum pressure requirements as early as the Winter of 2022/2023. An agreement for CNG in 2022 ensured Enbridge Gas maintained a safe and reliable system for customers in the Kingston project service area. The CNG agreement was executed July 1, 2022, for the winters of 2022/2023 and 2023/2024 to ensure an in-service date of December 1, 2022. The contracted CNG service is an enabling payment to a competitive service provider, where Enbridge does not own the asset, per the IRP Decision EB-2019-0091. The 2022 charges for the CNG Agreement were approved for recovery in the IRP Operating Costs Deferral Account[7] and the $0.278 is the 2023 cost of the CNG agreement.*

14) Please provide a major main map and network analysis showing pressures in the system including, specifically, the low point and location of contract customer for:
    a) Winter of 2022/23 prior to CNG
    b) Winter of 2022/23 after planned CNG
    c) Winter of 2022/23 after contract reduction implemented in Nov. 2022

15) What was the lowest pressure recorded at the low point in the Creekford Rd. system?
   a) What was the temperature at the time of the low point?
   b) Did EGI seek to cancel or otherwise redeploy the CNG system after the winter of 2022/23?
      i) If not, why not?

REF: Exhibit C, Tab 1, pg. 25

Preamble: EGI evidence states: *As previously noted, Bill 93 has resulted in increased labour rates for LSPs which has created parallel incremental costs in the Enbridge Gas VMS program since this service is performed by the same contractors. The 2021 average external contractor cost per hour was $82 and the 2023 average external contractor cost per hour was $146, a 78% increase.*

16) When did EGI perform the last RFP for the Locate Service Provider(s)?
   a) Given the seasonality of locates (e.g. spring peak), how did EGI mitigate the costs of timely locate provision?

REF: Exhibit D, Tab 1, pg. 8

Preamble: EGI evidence states: *As detailed in Section 3.3, Enbridge Gas is also seeking OEB approval to establish a Fugitive Emissions Measurement Administration Deferral Account (FEMADA) to record administrative costs associated with the implementation of the Company's fugitive emissions investigation plan.*

We would like to understand EGI's position on recovery of costs for enhanced leak detection given increases in UFG.

17) Please explain why EGI believes that leak detection and reduction in fugitive emissions are not the responsibility of a gas utility and therefore part of the O&M budget.

REF: Exhibit D, Tab 1, pg. 12

Preamble: EGI evidence states: *Importantly, nearly all comparable utility groups set out in Figure 2 also experienced a significant increase in UFG volumes in 2022. It is reasonable to assume that such trends in UFG volumes or related trends in UFG costs may be reflective of common macro- economic, geo-political, and/or national/continental weather trends, which have the potential to impact UFG volumes* *or costs broadly across the industry. Such trends highlight the value of comparing UFG volumes and costs experienced by a single utility to relevant peer groups over time.*

We would like to understand what is being communicated as rationale for UFG costs.

18) Please explain how UFG volumes and costs are impacted by:
   a) Common macroeconomic trends
   b) Geo-political trends
   c) National/Continental weather trends

REF: Exhibit D, Tab 1, pg. 15

Preamble: EGI evidence states: *Deliveries are the volumes of gas delivered by Enbridge Gas from its integrated storage, transmission, and distribution systems to various interconnects and measured via custody transfer measurement, including:*
.....
- *Company blowdown gas (i.e., an estimate of volumes typically purged or flared for operational maintenance purposes).*

19) Please explain how EGI is estimating these blowdown gas volumes.
   a) More importantly, please explain how EGI is mitigating these volumes being flared, or worse, emitted.

REF: Exhibit D, Tab 1, pg. 18

20) Using the approach in Table 2, please explain how the company handles reporting, particularly for year-end, if Month 1 is December and Month 2 is January.

REF: Exhibit D, Tab 1, pg. 25

Preamble: EGI evidence states: *On a monthly basis, the determination of Sendout includes an entry to record operational blowdowns or flaring associated with compressor facilities as noted in the discussion on Sendout above. By accounting for the volumes associated with these operational blowdowns or flaring, these volumes are removed from Sendout and as such do not contribute to calculated UFG volumes. A* *similar entry is recorded, where necessary, for blowdowns or flaring associated with capital projects.*

We are encouraged that the operational blowdowns or flaring but would like to understand how these commodity and emissions costs are accounted for.

21) Please explain where the commodity and emissions costs are allocated for:
   a) Capital projects
   b) Operations
   c) Maintenance projects

REF: Exhibit D, Tab 1, pg. 26

Preamble: EGI evidence states: *Like the accounting treatment currently applicable to the EGD Rate Zone UAFVDA, the proposed harmonized accounting order includes a provision enabling the Company to adjust for differences in estimated UFG and actual UFG to minimize timing variance(s) across fiscal years for all rate zones. The OEB accepted the Company's proposed accounting order and treatment effective January 1, 2024.*

22) What was applied to the UGL Rate Zone for 2023?

REF: Exhibit D, Tab 1, pg. 29-30

Preamble: EGI evidence states: *In 2023, the Company supported revisions to the specifications for compliance sampling used for seal extension and is currently working with Measurement Canada on pressure factor metering (PFM) specifications modernization and on specifications for ultrasonic meters.*

23) Please summarize the supported revisions and the estimated costs and benefits associated with the revisions, if and when, implemented.

REF: Exhibit D, Tab 1, pg. 34-35 and Table 5

Preamble: We would like to understand the issue of Historical Vacant Premises Lockouts, what has been found and the impact on the historic lost.

24) Please extend Table 5 to show the number from each year were resolved and the amount of gas that was "found" and any recoveries from the building owner.
  a) How were the gas costs associated with the found gas allocated?

REF: Exhibit D, Tab 1, pg. 38

Preamble: EGI evidence states: *As noted in its 2024 Phase 1 Rebasing application,40 Enbridge Gas is committed to Advanced Metering Infrastructure (AMI) and advised that it plans to file a stand-alone AMI application as soon as practicable that will request approval from the OEB for funding and to implement an AMI solution.*

25) Please provide EGI's most recent assessment of the cost and benefits of an AMI system in the EGI franchise.
  a) If not available, please provide a recent cost/benefit analysis that has been published for a gas-only utility in North America.

REF: Exhibit D, Tab 1, pg. 40

Preamble: EGI evidence states: *For communities that fall within more than one elevation zone (with an elevation difference exceeding 110 m between maximum/minimum elevations), unique elevation factors (e.g., air pressure, barometric pressure area) may need to be established in the Company's billing systems to adjust for the effect of atmospheric pressure on volumes of natural gas delivered.*

26) Please confirm that these Measurement Canada standards have been in place for decades.
  a) Please describe the UGL and EGD compliance with these requirements and provide the year of implementation of the standards.
  b) Please explain what has changed such that impacts of elevation difference would be resulting in unaccounted for gas.

REF: Exhibit D, Tab 1, pg. 42

Preamble: EGI evidence states: *Given the magnitude of natural gas volumes consumed by General Service customers, the Company expects that replacement of manual meter reading with an automated and remote process for those customers could significantly reduce incidence of billing based on estimated Consumption and related UFG volumes.*

In past proceedings, EGI has stated that billing problems did not impact UFG. The above reference seems to suggest it does.

27) Please explain how billing based on estimated consumption could contribute to UFG.
   a) Please provide the amounts quantified for each UGL and EGD Rate Zones for each year of 2021, 2022 and 2023.

REF: Exhibit D, Tab 1, pg. 47 and Table 8

Preamble: EGI evidence states: *Said differently, to the extent that a variance existed between estimated Consumption and actual Consumption for the Union Rate Zones, any adjustment(s) made after December have historically been recorded in the subsequent fiscal year. As a result, unbilled estimate-related UFG volumes for the Union Rate Zones increased UFG volumes in 2022 and subsequently suppressed UFG volumes in 2023.*

28) Please describe the impacts of these adjustments and any impact on ratepayers given the deadband.

REF: Exhibit D, Tab 1, pg. 52-57 and Table 9 and 10

Preamble: EGI evidence states: *Distribution pipeline system station pressures are typically held constant year-round and demands reduce over the length of each segment.*

29) Please explain the changes in minimum linepack in the EGD system from 2022 to 2023, especially for distribution given the above reference.
   a) Did the reduction in linepack provide more gas into Sendout thus increasing UFG? Please explain fully.

30) Has EGI assessed reducing distribution pressures in the non-heating seasons as a means of reducing fugitive emissions?
   i) If so, please explain
   ii) If not, why not?

31) Please provide Table 10 values for December 2023 and January 2024.
   a) Please describe and quantify the impact on 2023 year-end.

REF: Exhibit D, Tab 1, pg. 61 and Table 11

32) Please provide a breakdown of the components that contribute to such a high vehicle cost.

REF: Exhibit D, Tab 1, pg. 61

Preamble: EGI evidence states: *STO fugitive emissions are already being measured and quantified three times per year.*

33) How are the measurements determined and quantified.
   a) Please provide the last 3 years of measurement for STO fugitive emissions.
   b) Please provide the measurements disaggregated by storage and transmission.

REF: Exhibit D, Tab 1, pg. 66

Preamble: EGI evidence states: *To support implementation of the Fugitive Emissions Investigation Plan, Enbridge Gas is seeking OEB approval to establish a Fugitive Emissions Measurement Administration Deferral Account (FEMADA) to record the incremental administration costs, inclusive of Pilot costs, incurred to implement the plan.*

34) Please provide the principled basis and other justification for considering reducing fugitive emissions outside of the scope of normal utility operations to operate a safe, secure delivery system.

REF: Exhibit E, Tab 1, pg. 8-11

35) Please provide the total amount of Short-term storage sold disaggregated between peak and non-peak storage.
   a) Please provide the provide the monthly pricing, gross revenue by month and the costs identified by their source to arrive at net revenue.

REF: Exhibit E, Tab 1, pg. 13-18 and Tables 1-3 and Schedule 5

36) Please provide in Excel format with accompanying description, how the 2023 Target and Actual NAC's for M1 and M2 in Tables 1 and 2 are determined.
   a) Please provide in Excel format the monthly data and determination of the values in Schedule 5.
   b) For 2023 calculations, please provide and describe the selection of the months used for the determination of storage amounts (from 2022, 2023 or 2024)