

ONTARIO ENERGY BOARD NOTICE TO CUSTOMERS OF ENBRIDGE GAS INC.

**Enbridge Gas Inc. has applied to dispose of
the balances of certain deferral and variance accounts.**

Learn more. Have your say.

If the application is approved as filed, a typical residential customer of Enbridge Gas Inc. will see the following one-time billing adjustment, effective January 1, 2023:

EGD Rate Zone (former Enbridge Gas Distribution Inc. customers)

- **Residential Rate 1 Sales Service and Direct Purchase** customers will see a one-time billing charge of \$5.01, effective January 1, 2023.

Union Rate Zone (former Union Gas Limited customers)

- **Union South Residential Rate M1 Sales Service** customers will see a one-time billing charge of \$9.34, effective January 1, 2023.
- **Union South Residential Rate M1 Direct Purchase** customers will see a one-time billing charge of \$1.91, effective January 1, 2023.
- **Union North-West Residential Rate 01 Sales Service and Direct Purchase** customers will receive a one-time billing credit of \$17.33, effective January 1, 2023.
- **Union North-East Residential Rate 01 Sales Service and Direct Purchase** customers will see a one-time billing charge of \$7.78, effective January 1, 2023.

Other customers, including businesses, may also be affected.

Under the OEB-approved Earnings Sharing Mechanism, Enbridge Gas Inc. is required to share with customers any earnings that are 150 basis points over the OEB-approved return on equity. Enbridge Gas Inc. says that its 2021 earnings were below the 150 basis point threshold and as a result it is not proposing to share any earnings with customers.

THE ONTARIO ENERGY BOARD WILL HOLD A PUBLIC HEARING

The Ontario Energy Board (OEB) will hold a public hearing to consider Enbridge Gas's application. During this hearing, which could be an oral or written hearing, we will review Enbridge Gas's 2021 earnings and the deferral account balances that are requested for disposition. We will also hear questions and arguments from individuals that have registered to participate (called intervenors) in the OEB's hearing. At the end of this hearing, the OEB will decide whether to approve Enbridge Gas's request to dispose of the deferral account balances.

The OEB is an independent and impartial public agency. We make decisions that serve the public interest. Our goal is to promote a financially viable and efficient energy sector that provides you with reliable energy services at a reasonable cost.

BE INFORMED AND HAVE YOUR SAY

You have the right to information regarding this application and to be involved in the process.

- You can review Enbridge Gas's application on the OEB's website now
- You can file a letter with your comments, which will be considered during the hearing
- You can become an intervenor. As an intervenor, you can ask questions about Enbridge Gas's application and make arguments on whether the OEB should approve Enbridge Gas's request. Apply by **July 8, 2022** or the hearing will go ahead without you and you will not receive any further notice of the proceeding
- At the end of the process, you can review the OEB's decision and its reasons on our website

The OEB intends to consider cost awards in this proceeding that are in accordance with the Practice Direction on Cost Awards and only in relation to the following:

1) The review of the following deferral and variance accounts:

EGD Rate Zone (former Enbridge Gas Distribution Inc.) Accounts

- Storage and Transportation Deferral Account
- Transactional Services Deferral Account
- Unaccounted for Gas Variance Account
- Average Use True-Up Variance Account
- Deferred Rebate Account
- Transition Impact of Accounting Changes Deferral Account
- OEB Cost Assessment Variance Account
- Dawn Access Costs Deferral Account

Union Rate Zones (former Union Gas Limited) Accounts

- Upstream Transportation Optimization Deferral Account
- Unabsorbed Demand Costs Variance Account
- Short-Term Storage and Other Balancing Services
- Normalized Average Consumption Deferral Account
- Deferral Clearing Variance Account Variance Account
- OEB Cost Assessment Variance Account
- Parkway West Project Costs Deferral Account
- Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account
- Panhandle Reinforcement Project Costs Deferral Account
- Unaccounted for Gas Volume Variance Account
- Unaccounted for Gas Price Variance Account

Enbridge Gas Inc. Accounts

- Tax Variance - Accelerated Capital Cost Allowance – Enbridge Gas Inc.
- Integrated Resource Planning Operating Costs Deferral Account

- 2) The review of Enbridge Gas Inc.'s 2021 earnings, earnings sharing calculations and the 2021 Performance Scorecard.
- 3) The review of the methodology for the allocation and disposition of the deferral and variance account balances.

LEARN MORE

These proposed charges relate to Enbridge Gas's distribution services. The above referenced billing adjustment will appear as a separate line on your bill. Our file number for this case is **EB-2022-0110**. To learn more about this hearing, find instructions on how to file a letter with your comments or become an intervenor, or to access any document related to this case, please select the file number **EB-2022-0110** from the list on the OEB website: www.oeb.ca/notice. You can also phone our Public Information Centre at 1-877-632-2727 with any questions.

ORAL VS. WRITTEN HEARINGS

There are two types of OEB hearings – oral and written. Enbridge Gas has applied for a written hearing. The OEB will determine at a later date whether to proceed by way of a written or oral hearing. If you think an oral hearing is needed, you can write to the OEB to explain why by **July 8, 2022**.

PRIVACY

If you write a letter of comment, your name and the content of your letter will be put on the public record and the OEB website. However, your personal telephone number, home address and email address will be removed. If you are a business, all your information will remain public. If you apply to become an intervenor, all information will be public.

This rate hearing will be held under section 36 of the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B.



Ontario
Energy
Board

Commission
de l'énergie
de l'Ontario



Richard Wathy
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Regulatory Applications
Regulatory Affairs

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Richard.Wathy@enbridge.com
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
P. O. Box 2001
50 Keil Drive North
Chatham, ON N7M 5M1

June 17, 2022

VIA RESS AND EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

**Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2022-0110
2021 Utility Earnings and Disposition of Deferral & Variance Account
Balances Application and Evidence**

Further to the submission filed on May 31, 2022, enclosed please find the following updated exhibits:

| Exhibit | Correction |
|---------------------|--|
| B-3-1, Page 2 and 6 | <p>The 2021 Actual balance for Corporate Shared Services and Compensation and Benefits were misstated, resulting in an incorrect \$ and % change for those categories. There was no impact on Total Utility O&M.</p> <p>An updated Table 1 and Appendix A has been provided.</p> |

In the event that you have any questions on the above or would like to discuss in more detail, please do not hesitate to contact me.

Sincerely,

(Original Digitally Signed)

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)

EXHIBIT LIST

A – Overview and Introduction

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|---------------------------------|
| A | 1 | | Exhibit List |
| | 2 | | Application |
| | 3 | | Overview and Approvals Required |

B- Utility Results and Earning Sharing

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|--|
| B | 1 | | 2021 Earnings Sharing Amount and Determination Process |
| | | 1 | Return on Rate Base & Equity and Earning Sharing Determination |
| | | 2 | Utility Income |
| | | 3 | Utility Income Tax |
| | | 4 | Utility Rate Base and Continuity Schedules |
| | | 5 | Capital Structure and Cost of Capital |
| | | 6 | Reconciliation of Audited Income to Corporate |
| | 2 | 1 | Delivery Revenue by Service Type and Rate Class |
| | | 2 | Total Customers and Revenue by Service Type and Rate Class |

B- Utility Results and Earning Sharing

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|--|
| B | 2 | 3 | Revenue from Regulated Storage and Transportation of Gas |
| | | 4 | Other Revenue |
| | 3 | 1 | Operating and Maintenance Expense |
| | | 2 | Capital Expenditure |
| | | 3 | Summary of Capital Cost Allowance |

C- Enbridge Gas Inc 2021 Deferral and Variance Accounts

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|---|
| C | 1 | | Enbridge Gas Inc Deferral and Variance Accounts |
| | | 1 | Deferral and Variance Actual and Forecast Balances |
| | | 2 | Summary of Accounting Policy Changes Deferral Account |
| | | 3 | Calculation of Bill C-97 Accelerated CCA Impact on TVDA |

D - EGD Rate Zone Deferral and Variance Accounts

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|--|
| D | 1 | | Deferral & Variance Accounts Requested for Clearance – EGD Rate Zone |
| | | 1 | Breakdown of the Storage and Transportation Deferral Account |
| | | 2 | Breakdown of Transactional Services Revenue by Type of Transaction |
| | | 3 | 2021 UAFVA |
| | | 4 | Breakdown of the Average Use True-up Variance Account |
| | | 5 | Storage RFP Letter |
| | | 6 | Storage RFP Summary (Redacted) |

E – Union Rate Zones Deferral and Variance Accounts

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|---|
| E | 1 | | Deferral & Variance Accounts Requested for Clearance – Union Rate Zones |
| | | 1 | Breakdown of Upstream Transportation Optimization Deferral Account |
| | | 2 | Breakdown of Short Term Storage Deferral Account |
| | | | Appendix A – 2021 Storage Space and Deliverability |
| | | 3 | Summary of Non-Utility Storage Balances |

E – Union Rate Zones Deferral and Variance Accounts

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|--|
| E | 1 | 4 | Allocation of Short Term Peak Storage Revenues between Utility/Non-Utility |
| | | 5 | Breakdown of Deferral Clearing Variance Account |
| | | 6 | Calculation of Balances by Rate Class in the NAC Deferral Account |
| | | 7 | Calculation of Allocation of Short Term Transportation Revenues to the Lobo D / Bright C / Dawn H Compressor Project Cost Deferral Account |

F – Rate Allocation

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|---|
| F | 1 | | Allocation and Disposition of 2020 Deferral and Variance Account Balances |
| | | 1 | Split of EGI Account Balances to Rate Zones |
| | 2 | 1 | EGD - Unit Rate and Type of Service |
| | | 2 | EGD - Balances to be Cleared |
| | | 3 | EGD - Classification and Allocation of Deferral and Variance Account Balances |
| | | 4 | EGD - Allocation by Type of Service |
| | | 5 | EGD - Unit Rate by Type of Service |
| | | 6 | EGD - Bill Adjustment for Typical Customers |

F – Rate Allocation

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|---|
| F | 3 | 1 | Union – Unit Rate and Type of Service |
| | | 2 | Union - Balances to be Cleared |
| | | 3 | Union – Classification and Allocation of Deferral Variance Account Balances |
| | | 4 | Union - Unit Rates for Disposition |
| | | 5 | Union - Bill Adjustment for Typical Customer |

G – OEB Scorecard

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|------------------------|
| G | 1 | | 2021 Scorecard Results |
| | | 1 | OEB Scorecard |

H – IRP Annual Report

| <u>Exhibit</u> | <u>Tab</u> | <u>Schedule</u> | <u>Contents</u> |
|----------------|------------|-----------------|--|
| H | 1 | | IRP Annual Report and IRP Technical Working Group Report |

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*,
1998, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Enbridge
Gas Inc. for an order or orders clearing certain
commodity and non-commodity related deferral or
variance accounts.

APPLICATION

1. Enbridge Gas Distribution Inc. (referred to in the evidence as EGD, Enbridge or the Company) and Union Gas Limited (referred to in the evidence as Union or the Company) (together the Utilities) were Ontario corporations incorporated under the laws of the Province of Ontario carrying on the business of selling, distributing, transmitting and storing natural gas within the meaning assigned in the *Ontario Energy Board Act*, 1998 (the Act). In the August 30, 2018 EB-2017-0306/0307 Decision and Order (the MAADs Decision), the Ontario Energy Board (OEB) approved the amalgamation of the Utilities, as well as a five-year deferred rebasing term during which a price cap rate-setting model would apply.
2. Effective January 1, 2019 the Utilities amalgamated to become Enbridge Gas Inc. (Enbridge Gas). Following amalgamation, Enbridge Gas has maintained the existing rates zones of EGD and Union (the EGD, Union North West, Union North East and Union South rate zones).¹ Enbridge Gas has also maintained most of the existing deferral and variance accounts for each Rate Zone.

¹ Collectively the Union North West, Union North East and Union South rates zones are referred to as "Union rate zones". Union North West and Union North East are collectively referred to as "Union North".

3. Enbridge Gas, the Applicant, hereby applies to the OEB, pursuant to Section 36 of the *Ontario Energy Board Act*, 1998, for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

Earnings Sharing

4. In the MAADs Decision, the OEB approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the deferred rebasing period, where each year any earnings in excess of 150 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between the Utilities and ratepayers.
5. In 2021, Enbridge Gas's actual utility earnings did not exceed the OEB-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

Enbridge Gas Inc.

6. The OEB has approved several deferral and variance accounts that relate to Enbridge Gas as a whole (and not to specific Rate Zone(s)). These accounts are listed at Exhibit C, Tab 1, Schedule 1.
7. Enbridge Gas proposes to clear the 2021 balance in the Tax Variance Deferral Account (TVDA). Enbridge Gas is not seeking approval to clear any part of the balance in the Accounting Policy Changes Deferral Account (APCDA), in the Covid-19 Emergency Incremental Cost Deferral Account (COVEICDA) and in the Incremental Capital Module Deferral Account (ICMDA). Details on these accounts are presented in this application for information purposes. The balances in these accounts will be brought forward for clearance in a future application.

EGD Rate Zone

8. As approved in the MAADs Decision and the 2019 Rates Case (EB-2018-0305), Enbridge Gas has maintained substantially the same deferral and variance accounts for the EGD rate zone as during its 2014-2018 Custom IR term.
9. Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone deferral and variance accounts for 2021 as set out at Exhibit C, Tab 1, Schedule 1.

Union Rate Zones

10. As approved in the MAADs Decision and the 2019 Rates Case (EB-2018-0305), Enbridge Gas has maintained substantially the same deferral and variance accounts for the Union Rate Zones as during its 2014-2018 IR term.
11. Enbridge Gas seeks approval to clear the final balances of certain Union rate zones deferral and variance accounts for 2021 as set out at Exhibit C, Tab 1, Schedule 1.

Relief Requested

12. Enbridge Gas therefore applies to the OEB for such final, interim or other orders as may be necessary or appropriate for the clearance or disposition of the 2021 deferral and variance accounts requested in Exhibit C, Tab 1, Schedule 1. The proposed manner of disposition is described at Exhibit F. Enbridge Gas proposes to clear the balances in these accounts with the first available QRAM application following the OEB's approval, as early as January 1, 2023.
13. Enbridge Gas requests that certain information included at Exhibit D, Tab 1, Schedule 6 be treated as confidential under the OEB's Practice Direction on Confidential Filings. Equivalent information has been treated as confidential in prior deferral and variance account clearance proceedings.

14. Enbridge Gas requests that this proceeding be heard in writing.
15. Enbridge Gas further applies to the OEB pursuant to the provisions in the Act and the OEB's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.
16. This Application is supported by written evidence. This evidence may be amended from time to time as required by the OEB, or as circumstances may require.
17. The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.
18. Enbridge Gas requests that a copy of every document filed with the OEB in this proceeding be served on the Applicant and Applicant's counsel, as follows:

The Applicant:

Mr. Richard Wathy
Technical Manager, Regulatory Applications
Enbridge Gas Inc.

| | |
|------------------------------|---|
| Address for personal service | Enbridge Gas Inc. P. O. Box 2001 50 Keil Drive North Chatham, ON N7M 5M1 |
|------------------------------|---|

| | |
|------------|--|
| Telephone: | 519-365-5376 |
| Fax: | (519) 436-4641 |
| Email: | Richard.Wathy@enbridge.com EGIRegulatoryproceedings@enbridge.com |

- and –

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service
and mailing address:

Brookfield Place, P.O. Box 754
Suite 1800, 181 Bay Street
Toronto, Ontario M5J 2T9

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416-863-1500

Fax:

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Email:

dstevens@airdberlis.com

DATED: May 31, 2022, at Chatham, Ontario

ENBRIDGE GAS INC.

[Original digitally signed by]

Richard Wathy
Technical Manager, Regulatory
Applications

2021 DEFERRAL ACCOUNT DISPOSITION AND EARNINGS SHARING
OVERVIEW AND APPROVALS REQUESTED

1. Enbridge Gas Inc. (Enbridge Gas) is applying to the Ontario Energy Board (OEB) pursuant to section 36 of the *OEB Act* for approval to dispose and recover certain 2021 deferral and variance account final balances for Enbridge Gas, and the Enbridge Gas Distribution (EGD) and Union Gas (Union)¹ rate zones. Enbridge Gas is also presenting the 2021 earnings sharing mechanism (ESM) calculations for the amalgamated utility.
2. The evidence in this Application is organized as follows:
 - Exhibit A: Overview and Introduction
 - Exhibit B: 2021 Utility Results and Earnings Sharing Amount
 - Exhibit C: Enbridge Gas Inc. 2021 Deferral and Variance Accounts
 - Exhibit D: EGD Rate Zone Deferral and Variance Accounts
 - Exhibit E: Union Rate Zones Deferral and Variance Accounts
 - Exhibit F: Rate Allocation
 - Exhibit G: OEB Scorecard
 - Exhibit H: IRP Annual Report (to be filed at a later date)
3. Enbridge Gas proposes that the impacts which result from the disposition of 2021 deferral and variance account balances be implemented with the first available QRAM application following the OEB's approval, as early as January 1, 2023, to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism (QRAM).

¹ "Union rate zones" collectively refers to Union North West, Union North East and Union South.

1. Relief requested

4. Enbridge Gas seeks approval to clear the final balances of certain Enbridge Gas, EGD rate zone, and Union rate zones 2021 deferral and variance accounts. The balances of the 2021 deferral and variance accounts are set out at Exhibit C, Tab 1, Schedule 1. For ease of reference, a copy of Exhibit C, Tab 1, Schedule 1 is attached at Appendix A to this exhibit.
5. Explanations for the balances in each account are set out at Exhibit C (Enbridge Gas Inc.), Exhibit D (EGD rate zone) and Exhibit E (Union rate zones). The evidence also indicates which accounts Enbridge Gas does not seek to clear in this proceeding. The proposed clearance methodology for the accounts being cleared is set out at Exhibit F.
6. In the MAADs Decision (EB-2017-0306/0307), the OEB approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the 2019-2023 deferred rebasing period, where each year any earnings in excess of 150 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between Enbridge Gas and ratepayers.
7. Enbridge Gas's actual 2021 utility earnings did not exceed the OEB-approved ROE by more than 150 basis points. Accordingly, no ESM amount is proposed to be shared with ratepayers.

2. Disposition of deferral and variance accounts

8. Integration of the legacy billing systems for EGD and Union Gas enables Enbridge Gas to dispose of balances in the 2021 deferral and variance accounts as a one-time adjustment for all customers. Enbridge Gas proposes to dispose of the 2021 deferral

and variance accounts as a one-time adjustment for all general service, in-franchise contract and ex-franchise rate classes.

9. The proposed approach to the one-time adjustment is consistent between the EGD and Union rate zones and, subject to OEB approval as to timing, will be disposed of as part of the January 2023 bills that customers receive in February 2023.

3. Parkway west project costs account interim disposition

10. Enbridge Gas is seeking interim disposition of the 2021 balance in the Parkway West Project Costs Deferral Account (179-136), consistent with the 2016 to 2020 deferral and variance account disposition proceedings. In the 2016 deferral account proceeding, the OEB noted that “all parties agreed that the 2016 balance in the Parkway West Project Costs Account should be disposed of only on an interim basis to allow the OEB to perform a prudence review of the capital overspend prior to final disposition of the balance in the account.”² Consistent with this direction, Enbridge Gas will seek approval of the final disposition of this account as part of a subsequent proceeding when all the project costs have been incurred and the prudence of the project costs are assessed.

² EB-2017-0091 Updated Settlement Agreement Proposal, page 12.

| ENBRIDGE GAS DEFERRAL & VARIANCE ACCOUNT ACTUAL & FORECAST BALANCES | | | | | | |
|---|---|--------------------|--|-----------------------|--------------------|-------------------------|
| | | | Col. 1 | Col. 2 | Col. 3 | Col. 4 |
| | | | Forecast for clearance at January 1, 2023 | | | |
| Line No. | Account Description | Account Acronym | Principal (\$000's) | Interest (\$000's) | Total (\$000's) | Reference |
| <u>EGD Rate Zone Commodity Related Accounts</u> | | | | | | |
| 1. | Storage and Transportation D/A | 2021 S&TDA | 7,942.5 | 97.0 | 8,039.5 | D-1, Page 2 |
| 2. | Transactional Services D/A | 2021 TSDA | (3,904.1) | (35.4) | (3,939.6) | D-1, Page 4 |
| 3. | Unaccounted for Gas V/A | 2021 UAFVA | 753.9 | 4.5 | 758.4 | D-1, Page 6 |
| 4. | Total commodity related accounts | | 4,792.2 | 66.2 | 4,858.4 | |
| <u>EGD Rate Zone Non Commodity Related Accounts</u> | | | | | | |
| 5. | Average Use True-Up V/A | 2021 AUTUVA | 14,934.3 | 135.5 | 15,069.8 | D-1, Page 10 |
| 6. | Gas Distribution Access Rule Impact D/A | 2021 GDARIDA | - | - | - | D-1, Page 23 |
| 7. | Deferred Rebate Account | 2021 DRA | 4,359.4 | 53.5 | 4,412.9 | D-1, Page 12 |
| 8. | Transition Impact of Accounting Changes D/A | 2021 TIACDA | 4,435.8 | - | 4,435.8 | D-1, Page 1 |
| 9. | Electric Program Earnings Sharing D/A | 2021 EPESDA | - | - | - | D-1, Page 23 |
| 10. | Open Bill Revenue V/A | 2021 OBRVA | - | - | - | D-1, Page 23 |
| 11. | Ex-Franchise Third Party Billing Services V/A | 2021 EXFTPBSVA | - | - | - | D-1, Page 23 |
| 12. | RNG Injection Service V/A | 2021 RNGISVA | - | - | - | D-1, Page 23 |
| 13. | OEB Cost Assessment V/A | 2021 OEBCAVA | 2,550.3 | 31.5 | 2,581.8 | D-1, Page 13 |
| 14. | Dawn Access Costs D/A | 2021 DACDA | 1,968.0 | 17.9 | 1,985.9 | D-1, Page 16 |
| 15. | Pension and OPEB Forecast Accrual vs. Actual Cash Payment Di 2021 P&OPEBFAVACPDVA | | - | - | - | D-1, Page 23 |
| 16. | Total EGD Rate Zone (for clearance) | | 33,040.0 | 304.5 | 33,344.6 | |
| <u>Union Rate Zones Gas Supply Accounts</u> | | | <u>OEB Account Number</u> | | | |
| 17. | Upstream Transportation Optimization | 179-131 | 2021 | 8,616.3 | 78.2 | 8,694.5 E-1, Page 6 |
| 18. | Spot Gas Variance Account | 179-107 | 2021 | - | - | - E-1, Page 58 |
| 19. | Unabsorbed Demand Costs Variance Account | 179-108 | 2021 | (1,665.6) | (28.3) | (1,693.9) E-1, Page 1 |
| 20. | Base Service North T-Service TransCanada Capacity | 179-153 | 2021 | 83.5 | 0.9 | 84.4 E-1, Page 52 |
| 21. | Total Gas Supply Accounts | | | 7,034.2 | 50.8 | 7,085.0 |
| <u>Union Rate Zones Storage Accounts</u> | | | | | | |
| 22. | Short-Term Storage and Other Balancing Services | 179-70 | 2021 | 3,576.9 | 32.5 | 3,609.4 E-1, Page 8 |
| <u>Union Rate Zones Other Accounts</u> | | | | | | |
| 23. | Normalized Average Consumption | 179-133 | 2021 | 18,997.4 | 239.4 | 19,236.8 E-1, Page 13 |
| 24. | Deferral Clearing Variance Account | 179-132 | 2021 | (3,120.4) | (45.3) | (3,165.7) E-1, Page 21 |
| 25. | OEB Cost Assessment Variance Account | 179-151 | 2021 | 907.1 | 11.4 | 918.5 E-1, Page 49 |
| 26. | Unbundled Services Unauthorized Storage Overrun | 179-103 | 2021 | - | - | - E-1, Page 58 |
| 27. | Gas Distribution Access Rule Costs | 179-112 | 2021 | - | - | - E-1, Page 58 |
| 28. | Conservation Demand Management | 179-123 | 2021 | - | - | - E-1, Page 58 |
| 29. | Parkway West Project Costs | 179-136 | 2021 | (603.3) | (6.4) | (609.7) E-1, Page 25 |
| 30. | Brantford-Kirkwall/Parkway D Project Costs | 179-137 | 2021 | (45.0) | (0.4) | (45.4) E-1, Page 29 |
| 31. | Lobo C Compressor/Hamilton-Milton Pipeline Project Costs | 179-142 | 2021 | 24.0 | 0.4 | 24.4 E-1, Page 41 |
| 32. | Lobo D/Bright C/Dawn H Compressor Project Costs | 179-144 | 2021 | (112.1) | (3.6) | (115.7) E-1, Page 44 |
| 33. | Burlington-Oakville Project Costs | 179-149 | 2021 | (51.0) | (0.5) | (51.5) E-1, Page 47 |
| 34. | Panhandle Reinforcement Project Costs | 179-156 | 2021 | (3,162.0) | (35.9) | (3,197.9) E-1, Page 53 |
| 35. | Sudbury Replacement Project | 179-162 | 2021 | - | - | - E-1, Page 58 |
| 36. | Parkway Obligation Rate Variance | 179-138 | 2021 | - | - | - E-1, Page 58 |
| 37. | Unauthorized Overrun Non-Compliance Account | 179-143 | 2021 | - | - | - E-1, Page 58 |
| 38. | Pension and OPEB Forecast Accrual vs. Actual Cash Payment Di | 179-157 | 2021 | - | (1,345.6) | (1,345.6) E-1, Page 56 |
| 39. | Unaccounted for Gas Volume Variance Account | 179-135 | 2021 | 20,501.3 | 176.9 | 20,678.2 E-1, Page 31 |
| 40. | Unaccounted for Gas Price Variance Account | 179-141 | 2021 | 3,358.3 | 31.8 | 3,390.1 E-1, Page 38 |
| 41. | Total Other Accounts | | | 36,694.3 | (977.8) | 35,716.5 |
| 42. | Total Union Rate Zones (for clearance) | | | 47,305.4 | (894.6) | 46,410.8 |
| <u>EGI Accounts</u> | | | | | | |
| 43. | Earnings Sharing D/A | 179-382 | 2021 | - | - | - C-1, Page 1 |
| 44. | Tax Variance - Accelerated CCA - EGI | 179-383 | 2021 | (19,162.6) | (227.2) | (19,389.8) C-1, Page 12 |
| 45. | IRP Operating Costs Deferral Account | 179-385 | 2021 | 57.7 | 0.5 | 58.2 C-1, Page 15 |
| 46. | IRP Capital Costs Deferral Account | 179-386 | 2021 | - | - | - C-1, Page 1 |
| 47. | Expansion of Natural Gas Distribution Systems V/A | 179-380 | 2021 | - | - | - C-1, Page 1 |
| 48. | Total EGI Accounts (for clearance) | | | (19,104.9) | (226.7) | (19,331.6) |
| 49. | Total Deferral and Variance Accounts (for clearance) | | | 61,240.5 | (816.7) | 60,423.8 |
| <u>Not Being Requested for Clearance</u> | | | | | | |
| 50. | Accounting Policy Changes D/A - Pension - EGI | 179-120 | 2021 | 169,431.8 | - | 169,431.8 C-1, Page 2 |
| 51. | Accounting Policy Changes D/A - Other - EGI | 179-120 | 2019 | (1,749.5) | (52.8) | (1,802.3) C-1, Page 2 |
| 52. | Accounting Policy Changes D/A - Other - EGI | 179-120 | 2020 | (14,789.5) | (249.4) | (15,038.9) C-1, Page 2 |
| 53. | Accounting Policy Changes D/A - Other - EGI | 179-120 | 2021 | (13,864.6) | (168.8) | (14,033.4) C-1, Page 2 |
| 54. | Tax Variance - Integration Capital Additions - EGI | 179-383 | 2020 | (3,736.3) | (28.6) | (3,764.8) C-1, Page 12 |
| 55. | Tax Variance - Integration Capital Additions - EGI | 179-383 | 2021 | (10,462.6) | (80.0) | (10,542.7) C-1, Page 12 |
| 56. | Incremental Capital Module Deferral Account - EGD | 2020 ICMDA | 2020 | (254.0) | (3.2) | (257.2) C-1, Page 1 |
| 57. | Incremental Capital Module Deferral Account - EGD | 2021 ICMDA | 2021 | 175.5 | 2.0 | 177.5 C-1, Page 1 |
| 58. | Incremental Capital Module Deferral Account - UGL | 179-159 | 2019 | (6,869.6) | (196.1) | (7,065.7) C-1, Page 1 |
| 59. | Incremental Capital Module Deferral Account - UGL | 179-159 | 2020 | (5,615.4) | (91.9) | (5,707.2) C-1, Page 1 |
| 60. | Incremental Capital Module Deferral Account - UGL | 179-159 | 2021 | (14,353.4) | (147.2) | (14,500.6) C-1, Page 1 |
| 61. | Impacts Arising from the COVID-19 Emergency D/A - EGI | 2020 IACEDA | 2020 | 1,377.5 | 20.3 | 1,397.8 C-1, Page 1 |
| 62. | Impacts Arising from the COVID-19 Emergency D/A - EGI | 2021 IACEDA | 2021 | 34.3 | 0.4 | 34.7 C-1, Page 1 |
| 63. | Total of Accounts not being requested for clearance | | | 99,324.2 | (995.3) | 98,328.9 |

2021 ENBRIDGE GAS INC. EARNINGS SHARING AMOUNT
AND DETERMINATION PROCESS

1. For the year ended December 31, 2021, Enbridge Gas Inc. (Enbridge Gas, or the Company) is not in an earnings sharing position, as its achieved return on rate base and return on equity are below the threshold required for sharing. The earnings sharing calculation is shown at Exhibit B, Tab 1, Schedule 1, while supporting schedules that show the calculation of utility rate base, utility income and taxes, and the utility capital structure components, are contained in the balance of the B Exhibits. Exhibit B, Tab 1, Schedule 6 sets out a reconciliation of audited income to corporate income.
2. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2017-0306/0307 OEB Decision and Order, dated August 30, 2018, at pages 28 and 29, and within the EB-2017-0306 pre-filed evidence at Exhibit B, Tab 1, at pages 42 and 43:
 - if in any calendar year during the deferred rebasing term, Enbridge Gas's actual utility ROE is more than 150 basis points above the OEB-approved ROE for that year (updated annually by the OEB), then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge Gas and its ratepayers;
 - for the purposes of the ESM, Enbridge Gas shall calculate its earnings using generally accepted accounting principles (GAAP) consistent with its external reporting, including the regulatory rules prescribed by the OEB from time to time;
 - all revenues and costs that would otherwise be included in a cost of service application shall be included in the earnings sharing calculation.

3. While the threshold or benchmark for Enbridge Gas's earnings sharing has changed from that of each legacy utility¹, the general process followed for calculating earnings sharing amounts is consistent with each utilities prior incentive regulation terms.
4. As articulated above, within Exhibit B, Tab 1, Schedule 1, the Company has calculated earnings for sharing in two ways for confirmation purposes.
5. In part A), a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the calculation can be found. Column 3 contains results shown in millions of dollars, or percentages.

1. Part A)

6. The level of utility income, \$846.5 million (Line 4) divided by the level of utility rate base, \$14,216.1 million (Line 5) generates a utility return on rate base of 5.954% (Line 6).
7. When compared to the Company's required rate of return for ESM determination, of 6.167% (Line 7), as determined within the capital structure required in support of the determined rate base amount (inclusive of the 150 basis point deadband on ROE before earnings sharing is triggered), there is a resulting deficiency of 0.213% (Line 8) on total rate base.
8. As shown in Lines 9 through 11, the deficiency of 0.213% multiplied by the rate base of \$14,216.1 million, produces a net under earnings or deficiency of \$30.3 million, which from a pre-tax perspective (\$30.3 million divided by the reciprocal, 73.5%, of

¹ Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union).

the corporate tax rate which is 26.5%), results in a \$41.2 million gross amount of under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

2. Part B) (Confirming the Calculated Earnings Sharing)

9. Net utility income applicable to common equity is first determined.
10. The \$889.6 million (Line 14) of utility income before income tax, less utility taxes of \$43.1 million (Line 19), produces the \$846.5 million of utility income used in part A) above (at Line 4).
11. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) \$846.5 million utility income.
12. These reductions are shown at Lines 15, 16 and 17 which, along with the utility income tax reduction already mentioned and shown at Line 19, results in a net income applicable to common equity of \$473.3 million, shown at Line 20.
13. The \$473.3 million, divided by the deemed common equity level of \$5,117.8 million (Line 21, calculated as 36% of the \$14,216.1 million rate base) produces a return on equity of 9.249% (Line 23). When comparing the 9.249% achieved return on equity to the threshold ROE percentage of 9.840% (Line 22), which is the OEB-approved formula return on equity for 2021 of 8.340% plus the 150 basis point deadband before sharing, there is a deficiency in ROE of 0.591% (Line 24).
14. The 0.591% multiplied by the common equity level of \$5,117.8 million (Line 21) produces a net under earnings or deficiency of \$30.3 million, which from a pre-tax perspective (\$30.3 million divided by the reciprocal, 73.5%, of the corporate tax

rate), results in a \$41.2 million gross amount of under earnings, and therefore nothing to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

3. Process Description

15. The calculation of utility earnings and any earnings sharing requirement starts with financial results contained within the Enbridge Gas corporate trial balance. The Company notes that corporate trial balance includes the elimination of transactions between each of the rate zones. This predominantly relates to the elimination of regulated and unregulated storage and transmission revenues that would have been reflected in the Union rate zones, offset by a corresponding elimination of gas costs that would have been reflected for the EGD rate zone. This reflects the fact that from a corporate perspective, EGD rate zone delivery revenues are contributing to the costs of Union rate zones regulated and unregulated storage and transmission services.
16. From there, in order to calculate the utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the OEB and the standards associated with cost of service rate related accounting processes. Examples are:
 - determination of rate base amounts using the average of monthly averages value concept,
 - elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base; and,
 - elimination of corporate income taxes due to the determination of income taxes specific to utility results.

17. In addition, Enbridge Gas has made the appropriate adjustments in relation to non-standard legacy EGD and Union rate regulated items which the OEB has either decided in the past or are required in order to determine an appropriate utility return on equity. Examples are:

- rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
- exclusion of non-utility or unregulated activities; and,
- elimination of approved shareholder incentives (such as Demand Side Management incentives, amounts related to Transactional Services, short-term storage, and net optimization incentives, and amounts related to Open Bill program incentives).

SUMMARY
RETURN ON RATE BASE & EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS INC.

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2021

| Line No. | Col. 1 Description | Col. 2 Reference | Col. 3 Actual |
|----------|---|---------------------------------|----------------------|
| 1. | Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency | | |
| | | | (\$Millions) & (%'s) |
| 2. | Utility Income before Income Tax | (Ex. B, Tab 1, Sch. 2) | 889.6 |
| 3. | Less: Income Taxes | (Ex. B, Tab 1, Sch. 3) | 43.1 |
| 4. | Utility Income | | 846.5 |
| 5. | Utility Rate Base | (Ex. B, Tab 1, Sch. 4) | 14,216.1 |
| 6. | Indicated Return on Rate Base % | (line 4 / line 5) | 5.955% |
| 7. | Less: Required Rate of Return % | (Ex. B, Tab 1, Sch. 5) | 6.167% |
| 8. | (Deficiency) / Sufficiency % | | -0.213% |
| 9. | Net Earnings (Deficiency) / Sufficiency | (line 5 x line 8) | (30.2) |
| 10. | Provision for Income Taxes | | (10.9) |
| 11. | Gross Earnings (Deficiency) / Sufficiency | (line 9 / 73.5%) | (41.1) |
| 12. | 50% Earnings sharing to ratepayers | (if line 11 > 1, line 11 x 50%) | - |
| 13. | Part B) Return on Equity & Revenue (Deficiency) / Sufficiency | | |
| 14. | Utility Income before Income Tax | (Ex. B, Tab 1, Sch. 2) | 889.6 |
| 15. | Less: Long Term Debt Costs | (Ex. B, Tab 1, Sch. 5) | 371.3 |
| 16. | Less: Short Term Debt Costs | (Ex. B, Tab 1, Sch. 5) | 1.9 |
| 17. | Less: Cost of Preferred Capital | (Ex. B, Tab 1, Sch. 5) | 0.0 |
| 18. | Net Income before Income Taxes | | 516.5 |
| 19. | Less: Income Taxes | (Ex. B, Tab 1, Sch. 3) | 43.1 |
| 20. | Net Income Applicable to Common Equity | (line 18 - line 19) | 473.4 |
| 21. | Common Equity | (Ex. B, Tab 1, Sch. 5) | 5,117.8 |
| 22. | Approved ROE (including deadband before earning sharing) % | (Board-approved + 150bp) | 9.840% |
| 23. | Achieved Rate of Return on Equity % | (line 20 / line 21) | 9.249% |
| 24. | Resulting (Deficiency) / Sufficiency in Return on Equity % | | -0.591% |
| 25. | Net Earnings (Deficiency) / Sufficiency | (line 21 x line 24) | (30.2) |
| 26. | Provision for Income Taxes | | (10.9) |
| 27. | Gross Earnings (Deficiency) / Sufficiency | (line 25 / 73.5%) | (41.1) |
| 28. | 50% Earnings sharing to ratepayers | (if line 27 > 1, line 27 x 50%) | - |

| EGI UTILITY INCOME | | | | | |
|--------------------|---|----------------------------|--------------------------------------|------------------------------|---|
| 2021 ACTUAL | | | | | |
| Line No. | Reference | Col. 1 Corporate (a) | Col. 2 Unregulated Storage (b) | Col. 3 Adjustments (c) | Col. 4 Utility Income (d) = (a)-(b)+(c) (\$Millions) |
| 1. | Gas sales and distribution (Ex. B, Tab 2, Sch. 2) | 4,513.2 | - | (32.6) (i) | 4,480.6 |
| 2. | Transportation (Ex. B, Tab 2, Sch. 3) | 143.0 | 0.4 | (0.8) (ii) | 142.0 |
| 3. | Storage (Ex. B, Tab 2, Sch. 3) | 159.7 | 153.6 | (0.1) (iii) | 6.0 |
| 4. | Other operating revenue (Ex. B, Tab 2, Sch. 4) | 64.3 | 1.8 | (13.4) (iv) | 49.1 |
| 5. | Other income (Ex. B, Tab 2, Sch. 4) | 7.2 | - | (6.3) (viii) | 0.9 |
| 6. | Total operating revenue | 4,887.4 | 155.8 | (53.1) | 4,678.5 |
| 7. | Gas costs | 2,146.2 | 20.2 | (15.4) (i) | 2,110.6 |
| 8. | Operation and maintenance (Ex. B, Tab 3, Sch. 1) | 938.6 | 18.5 | (4.0) (v) | 916.2 |
| 9. | Depreciation and amortization expense | 676.8 | 14.9 | (22.6) (vi) | 639.3 |
| 10. | Fixed financing costs | 6.3 | - | 0.5 (vii) | 6.8 |
| 11. | Municipal and other taxes | 117.9 | 1.8 | - | 116.1 |
| 12. | Cost of service | 3,885.8 | 55.4 | (41.5) | 3,788.9 |
| 13. | Utility income before income taxes | | | | 889.6 |
| 14. | Income tax expense (Ex. B, Tab 1, Sch. 3) | | | | 43.1 |
| 15. | Utility income | | | | 846.5 |

Notes on Adjustments:

| | | |
|--------|--|--------|
| (i) | Reclassification of Union rate zone optimization revenue as a cost of gas reduction | (15.4) |
| | Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues | (17.2) |
| | | (32.6) |
| (ii) | Elimination of the Union rate zone shareholder portion of net optimization activity (before tax) | (0.8) |
| (iii) | Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax) | (0.1) |
| (iv) | Adjust EGD rate zone OBA costs to reflect EB-2013-0099 approved unit costs agreed to be used for determining net revenue | (4.3) |
| | Elimination of EGD rate zone Open Bill shareholder incentive | 0.3 |
| | Elimination of EGD rate zone shareholder portion of transactional service revenues | (1.8) |
| | Elimination of demand-side management incentive | (6.9) |
| | Elimination of EGD rate zone net revenue from ABC T-service, considered to be non-utility | (0.8) |
| | | (13.4) |
| (v) | Elimination of donations | (3.6) |
| | Elimination of EB-2021-0204 Assurance of Voluntary Compliance amount | (0.1) |
| | Elimination of non-utility costs and expenses relating to support of the EGD rate zone ABC T-service program | (0.3) |
| | | (4.0) |
| (vi) | Eliminate amortization of PPD (purchase price discrepancy) | (22.5) |
| | Eliminate depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479) | (0.1) |
| | | (22.6) |
| (vii) | Interest on security deposits held during the year and included in elimination of corporate interest exp. Expense incurred to reduce bad debt. The average amount of the security deposit held during the year is applied as a reduction to the allowance for working capital in rate base | 0.5 |
| (viii) | Elimination of interest income from investments not included in utility rate base | (0.1) |
| | Elimination of interest income from affiliates | (1.6) |
| | Elimination of the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part VI.1 tax transfer to EGI | (4.6) |
| | | (6.3) |

CALCULATION OF EGI UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2021 ACTUAL

| Line No. | Col. 1 | Col. 2 | Col. 3 |
|--|-------------------------|----------------------------|--------------------------|
| | Federal (\$Millions) | Provincial (\$Millions) | Combined (\$Millions) |
| 1. Utility income before income taxes | 889.6 | 889.6 | |
| Add | | | |
| 2. Depreciation and amortization | 639.3 | 639.3 | |
| 3. Accrual based pension and OPEB costs | 37.6 | 37.6 | |
| 4. Other non-deductible items | 0.3 | 0.3 | |
| 5. Total Add Back | 677.2 | 677.2 | |
| 6. Sub-total | 1,566.9 | 1,566.9 | |
| Deduct | | | |
| 7. Capital cost allowance | 829.4 | 829.4 | |
| 8. Items capitalized for regulatory purposes | 152.9 | 152.9 | |
| 9. Amortization of share/debenture issue expense | 0.4 | 0.4 | |
| 10. Amortization of C.D.E. and C.O.G.P.E | - | - | |
| 11. Other | 6.3 | 6.3 | |
| 12. Cash based pension and OPEB costs | 42.1 | 42.1 | |
| 13. Total Deduction | 1,031.1 | 1,031.1 | |
| 14. Taxable income | 535.8 | 535.8 | |
| 15. Income tax rates | 15.00% | 11.50% | |
| 16. Tax provision excluding interest shield | 80.4 | 61.6 | 142.0 |
| Tax shield on interest expense | | | |
| 17. Rate base | 14,216.1 | | |
| 18. Return component of debt | 2.62% | | |
| 19. Interest expense | 373.1 | | |
| 20. Combined tax rate | 26.50% | | |
| 21. Income tax credit | | | (98.9) |
| 22. Total utility income taxes | | | 43.1 |

EGI UTILITY RATE BASE
2021 ACTUAL

| Line No. | Col. 1 | Col. 2 |
|---|------------------------|------------------------|
| | 2021 Actual | 2020 Actual |
| | (\$Millions) | (\$Millions) |
| <u>Property, Plant, and Equipment</u> | | |
| 1. Gross property, plant, and equipment | 21,522.4 | 20,582.1 |
| 2. Accumulated depreciation | <u>(7,994.0)</u> | <u>(7,571.2)</u> |
| 3. Net property, plant, and equipment | <u>13,528.4</u> | <u>13,010.8</u> |
| <u>Allowance for Working Capital</u> | | |
| 4. Materials and supplies | 92.5 | 82.2 |
| 5. ABC receivable | (15.5) | (22.3) |
| 6. Customer security deposits | (68.9) | (81.8) |
| 7. Prepaid expenses | 4.7 | 3.1 |
| 8. Balancing gas | 59.5 | 59.5 |
| 9. Gas in storage | 594.7 | 487.5 |
| 10. Working cash allowance | <u>20.9</u> | <u>23.0</u> |
| 11. Total Working Capital | <u>687.7</u> | <u>551.2</u> |
| 12. <u>Utility Rate Base</u> | <u><u>14,216.1</u></u> | <u><u>13,562.0</u></u> |

EGI UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

| Line No. | Col. 1 Gross Property, Plant, and Equipment (\$Millions) | Col. 2 Accumulated Depreciation (\$Millions) | Col. 3 Net Property, Plant, and Equipment (\$Millions) |
|--|---|---|---|
| EGD Rate Zone | | | |
| 1. Underground storage plant | 485.6 | (148.5) | 337.1 |
| 2. Distribution plant | 9,640.8 | (3,070.8) | 6,570.0 |
| 3. General plant | 660.6 | (493.6) | 167.0 |
| 4. Plant held for future use | 1.7 | (1.4) | 0.2 |
| 5. EGD Rate Zone Total | <u>10,788.6</u> | <u>(3,714.3)</u> | <u>7,074.3</u> |
| Union Rate Zones | | | |
| 6. Intangible plant | 1.7 | (1.3) | 0.4 |
| 7. Local storage plant | 32.0 | (17.8) | 14.2 |
| 8. Underground storage plant | 831.3 | (335.4) | 495.9 |
| 9. Transmission plant | 3,767.4 | (1,188.6) | 2,578.8 |
| 10. Distribution plant - Southern operations | 3,529.2 | (1,515.5) | 2,013.7 |
| 11. Distribution plant - Northern and Eastern operations | 2,134.6 | (980.1) | 1,154.5 |
| 12. General plant | 437.6 | (241.0) | 196.7 |
| 13. Union Rate Zones Total | <u>10,733.8</u> | <u>(4,279.7)</u> | <u>6,454.1</u> |
| 14. EGI Total | <u>21,522.4</u> | <u>(7,994.0)</u> | <u>13,528.4</u> |

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

| Line No. | | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 |
|--|--|--------------------------|--------------|--------------|--------------------------|-----------------------|--------------------------|-----------------------------|
| | | Opening Balance Dec.2020 | Additions | Retirements | Closing Balance Dec.2021 | Regulatory Adjustment | Utility Balance Dec.2021 | Average of Monthly Averages |
| | | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) |
| EGD Rate Zone Underground Storage Plant | | | | | | | | |
| 1. | Land and gas storage rights (450/451) | 47.6 | 1.3 | - | 48.9 | (1.0) | 47.9 | 46.6 |
| 2. | Structures and improvements (452) | 31.5 | 0.6 | - | 32.1 | (0.1) | 32.0 | 31.5 |
| 3. | Wells (453) | 70.0 | 22.4 | - | 92.4 | - | 92.4 | 71.0 |
| 4. | Well equipment (454) | 12.6 | 0.7 | - | 13.4 | - | 13.4 | 12.7 |
| 5. | Field Lines (455) | 115.4 | 12.3 | - | 127.7 | - | 127.7 | 115.9 |
| 6. | Compressor equipment (456) | 159.7 | 36.4 | - | 196.2 | (0.5) | 195.7 | 164.3 |
| 7. | Measuring and regulating equipment (457) | 11.2 | - | - | 11.2 | - | 11.2 | 11.2 |
| 8. | Base pressure gas (458) | 32.4 | - | - | 32.4 | - | 32.4 | 32.4 |
| 9. | Sub-Total | 480.5 | 73.8 | - | 554.3 | (1.5) | 552.7 | 485.6 |
| EGD Rate Zone Distribution Plant | | | | | | | | |
| 10. | Renewable Natural Gas (461) | - | - | - | - | - | - | - |
| 11. | Land (470) | 53.7 | 0.5 | - | 54.2 | - | 54.2 | 54.0 |
| 12. | Offers to purchase (470) | - | - | - | - | - | - | - |
| 13. | Land rights intangibles (471) | 63.8 | - | - | 63.8 | - | 63.8 | 63.8 |
| 14. | Structures and improvements (472) | 151.0 | 47.1 | (4.7) | 193.4 | (0.3) | 193.1 | 155.1 |
| 15. | Services, house reg & meter install. (473/474) | 3,306.0 | 204.9 | (9.9) | 3,501.0 | - | 3,501.0 | 3,372.2 |
| 16. | Mains (475) | 4,727.4 | 158.0 | 73.5 | 4,958.8 | (2.2) | 4,956.6 | 4,780.5 |
| 17. | NGV station compressors (476) | 5.5 | (0.3) | - | 5.2 | - | 5.2 | 5.2 |
| 18. | Measuring and regulating equip. (477) | 684.7 | 22.6 | (8.8) | 698.5 | (0.5) | 698.0 | 693.5 |
| 19. | Meters (478) | 519.6 | 29.0 | (21.3) | 527.3 | - | 527.3 | 516.5 |
| 20. | Sub-Total | 9,511.7 | 461.7 | 28.9 | 10,002.2 | (3.1) | 9,999.2 | 9,640.8 |
| EGD Rate Zone General Plant | | | | | | | | |
| 21. | Lease improvements (482) | 0.1 | (0.0) | - | 0.1 | (0.2) | (0.1) | (0.1) |
| 22. | Office furniture and equipment (483) | 21.0 | (0.2) | - | 20.7 | - | 20.7 | 20.5 |
| 23. | Transportation equipment (484) | 61.7 | 5.1 | (1.4) | 65.4 | (0.1) | 65.4 | 59.4 |
| 24. | NGV conversion kits (484) | 2.9 | (0.0) | - | 2.9 | - | 2.9 | 2.8 |
| 25. | Heavy work equipment (485) | 20.2 | 2.9 | - | 23.1 | - | 23.1 | 20.3 |
| 26. | Tools and work equipment (486) | 59.3 | 0.6 | - | 59.8 | - | 59.8 | 58.4 |
| 27. | Rental equipment (487) | 1.8 | (0.0) | - | 1.8 | - | 1.8 | 1.8 |
| 28. | NGV rental compressors (487) | 20.2 | (12.4) | - | 7.8 | - | 7.8 | 19.2 |
| 29. | NGV cylinders (484 and 487) | 1.0 | (0.4) | - | 0.6 | - | 0.6 | 0.6 |
| 30. | Communication structures & equip. (488) | 3.7 | (0.1) | (1.8) | 1.8 | - | 1.8 | 2.6 |
| 31. | Computer equipment (490) | 32.1 | 2.3 | (7.2) | 27.1 | - | 27.1 | 30.3 |
| 32. | Software Acquired/Developed (491) | 254.3 | 3.5 | (23.5) | 234.2 | - | 234.2 | 243.4 |
| 33. | CIS (491) | 127.1 | 10.9 | (124.1) | 13.8 | - | 13.8 | 111.2 |
| 34. | WAMS (489) | 92.1 | (2.2) | - | 89.9 | - | 89.9 | 90.0 |
| 35. | Sub-Total | 697.4 | 9.8 | (158.0) | 549.2 | (0.3) | 548.9 | 660.6 |

EGD Rate Zone Plant held for future use

| | | | | | | | | |
|-----|-------------------------|----------|-------|---------|----------|-------|----------|----------|
| 36. | Inactive services (102) | 1.7 | - | - | 1.7 | - | 1.7 | 1.7 |
| 37. | EGD Rate Zone Total | 10,691.2 | 545.3 | (129.1) | 11,107.3 | (4.8) | 11,102.5 | 10,788.6 |

Union Rate Zones Intangible Plant

| | | | | | | | | |
|-----|-------------------------------|-----|---|---|-----|---|-----|-----|
| 38. | Franchises and consents (401) | 1.2 | - | - | 1.2 | - | 1.2 | 1.2 |
| 39. | Other intangible plant (402) | 0.5 | - | - | 0.5 | - | 0.5 | 0.5 |
| 40. | Sub-Total | 1.7 | - | - | 1.7 | - | 1.7 | 1.7 |

Union Rate Zones Local Storage Plant

| | | | | | | | | |
|-----|-----------------------------------|------|-----|---|------|---|------|------|
| 41. | Land (440) | 0.0 | - | - | 0.0 | - | 0.0 | 0.0 |
| 42. | Structures and improvements (442) | 5.2 | 0.7 | - | 5.9 | - | 5.9 | 5.2 |
| 43. | Gas holders - storage (443) | 4.6 | 0.8 | - | 5.4 | - | 5.4 | 4.6 |
| 44. | Gas holders - equipment (443) | 20.2 | 0.0 | - | 20.2 | - | 20.2 | 20.2 |
| 45. | Regulatory Overheads | 1.8 | 0.3 | - | 2.1 | - | 2.1 | 1.9 |
| 46. | Sub-Total | 31.8 | 1.8 | - | 33.6 | - | 33.6 | 32.0 |

Union Rate Zones Underground Storage Plant

| | | | | | | | | |
|-----|--|-------|--------|---|-------|---|-------|-------|
| 47. | Land (450) | 7.2 | 2.4 | - | 9.6 | - | 9.6 | 7.3 |
| 48. | Land rights (451) | 32.0 | - | - | 32.0 | - | 32.0 | 32.0 |
| 49. | Structures and improvements (452) | 69.3 | 0.9 | - | 70.2 | - | 70.2 | 69.4 |
| 50. | Wells (453) | 48.0 | 1.1 | - | 49.1 | - | 49.1 | 48.5 |
| 51. | Field Lines (455) | 50.6 | 0.5 | - | 51.1 | - | 51.1 | 50.8 |
| 52. | Compressor equipment (456) | 470.1 | 2.9 | - | 473.0 | - | 473.0 | 470.6 |
| 53. | Measuring and regulating equipment (457) | 86.4 | (23.6) | - | 62.8 | - | 62.8 | 85.5 |
| 54. | Base pressure gas (458) | 36.2 | - | - | 36.2 | - | 36.2 | 36.2 |
| 55. | Regulatory Overheads | 18.1 | 3.6 | - | 21.7 | - | 21.7 | 19.4 |
| 56. | Sub-Total | 817.9 | (12.1) | - | 805.8 | - | 805.8 | 819.7 |

Union Rate Zones Transmission Plant

| | | | | | | | | |
|-----|---|---------|-------|-------|---------|---|---------|---------|
| 57. | Land (460) | 82.2 | 2.5 | - | 84.7 | - | 84.7 | 82.6 |
| 58. | Land rights (461) | 67.5 | 0.9 | - | 68.3 | - | 68.3 | 67.6 |
| 59. | Structures & improvements (462/463/464) | 166.3 | 0.8 | - | 167.1 | - | 167.1 | 166.3 |
| 60. | Mains (465) | 1,954.5 | 61.9 | (4.1) | 2,012.3 | - | 2,012.3 | 1,963.6 |
| 61. | Compressor equipment (466) | 942.6 | 3.0 | - | 945.7 | - | 945.7 | 943.4 |
| 62. | Measuring & regulating equipment (467) | 321.0 | 45.0 | - | 366.0 | - | 366.0 | 325.7 |
| 63. | Line Pack Gas | 7.5 | 0.0 | - | 7.5 | - | 7.5 | 7.5 |
| 64. | Regulatory Overheads | 200.1 | 31.4 | - | 231.5 | - | 231.5 | 210.7 |
| 65. | Sub-Total | 3,741.6 | 145.5 | (4.1) | 3,883.1 | - | 3,883.1 | 3,767.4 |

Union Rate Zones Distribution Plant - Southern Operations

| | | | | | | | | |
|-----|--|---------|-------|--------|---------|---|---------|---------|
| 66. | Land (470) | 12.6 | 4.1 | - | 16.7 | - | 16.7 | 15.3 |
| 67. | Land rights (471) | 8.9 | 0.2 | - | 9.1 | - | 9.1 | 8.9 |
| 68. | Structures and improvements (472) | 139.6 | 6.6 | - | 146.2 | - | 146.2 | 140.9 |
| 69. | Services - metallic (473) | 128.4 | 2.4 | (0.3) | 130.5 | - | 130.5 | 129.2 |
| 70. | Services - plastic (473) | 956.7 | 41.1 | (1.8) | 996.0 | - | 996.0 | 974.7 |
| 71. | Regulators (474) | 97.1 | 13.4 | (5.8) | 104.8 | - | 104.8 | 102.6 |
| 72. | House regulators & meter installations (474) | 76.9 | 10.3 | - | 87.2 | - | 87.2 | 78.1 |
| 73. | Mains - metallic (475) | 581.8 | 103.5 | (0.9) | 684.3 | - | 684.3 | 598.0 |
| 74. | Mains - plastic (475) | 706.4 | 44.4 | (0.5) | 750.3 | - | 750.3 | 721.0 |
| 75. | Measuring & regulating equipment (477) | 60.3 | 13.1 | - | 73.4 | - | 73.4 | 61.4 |
| 76. | Meters (478) | 373.3 | 21.4 | (3.3) | 391.4 | - | 391.4 | 380.8 |
| 77. | Regulatory Overheads | 315.2 | 40.4 | - | 355.6 | - | 355.6 | 329.9 |
| 78. | Sub-total | 3,457.2 | 300.8 | (12.7) | 3,745.4 | - | 3,745.4 | 3,540.8 |

Union Rate Zones Distribution Plant - Northern & Eastern Operations

| | | | | | | | | |
|-----|--|---------|-------|-------|---------|---|---------|---------|
| 79. | Land (470) | 5.0 | 0.3 | - | 5.3 | - | 5.3 | 5.2 |
| 80. | Land rights (471) | 10.6 | 0.3 | - | 10.9 | - | 10.9 | 10.7 |
| 81. | Structures and improvements (472) | 68.6 | 2.9 | - | 71.4 | - | 71.4 | 69.1 |
| 82. | Services - metallic (473) | 110.1 | 1.4 | (0.2) | 111.2 | - | 111.2 | 110.5 |
| 83. | Services - plastic (473) | 489.6 | 17.0 | (0.8) | 505.8 | - | 505.8 | 495.6 |
| 84. | Regulators (474) | 39.0 | 0.8 | (2.1) | 37.7 | - | 37.7 | 39.2 |
| 85. | House regulators & meter installations (474) | 41.5 | 0.7 | - | 42.3 | - | 42.3 | 41.7 |
| 86. | Mains - metallic (475) | 680.5 | 40.2 | (0.8) | 719.9 | - | 719.9 | 688.0 |
| 87. | Mains - plastic (475) | 238.7 | 7.9 | (0.2) | 246.3 | - | 246.3 | 240.5 |
| 88. | Measuring & regulating equipment (477) | 151.3 | 4.2 | - | 155.5 | - | 155.5 | 152.2 |
| 89. | Meters (478) | 96.8 | 6.3 | (0.9) | 102.2 | - | 102.2 | 97.3 |
| 90. | Regulatory Overheads | 173.1 | 32.5 | - | 205.6 | - | 205.6 | 184.5 |
| 91. | Sub-total | 2,104.7 | 114.4 | (5.0) | 2,214.1 | - | 2,214.1 | 2,134.6 |

Union Rate Zones General Plant

| | | | | | | | | |
|------|--------------------------------------|----------|---------|---------|----------|-------|----------|----------|
| 92. | Land (480) | 0.5 | - | - | 0.5 | - | 0.5 | 0.5 |
| 93. | Structures & improvements (482) | 73.8 | 16.3 | - | 90.2 | - | 90.2 | 78.4 |
| 94. | Office furniture and equipment (483) | 10.1 | 0.0 | (0.9) | 9.3 | - | 9.3 | 10.0 |
| 95. | Office equipment - computers (483) | 129.2 | 53.0 | (69.1) | 113.1 | - | 113.1 | 140.1 |
| 96. | Transportation equipment (484) | 64.6 | 6.4 | (5.1) | 65.9 | - | 65.9 | 64.7 |
| 97. | Heavy work equipment (485) | 19.2 | 2.3 | (0.5) | 21.0 | - | 21.0 | 19.3 |
| 98. | Tools and work equipment (486) | 39.2 | 2.2 | (6.1) | 35.3 | - | 35.3 | 38.8 |
| 99. | NGV fuel equipment (487) | 3.2 | 1.3 | - | 4.5 | - | 4.5 | 3.3 |
| 100. | Communication equipment (488) | 14.3 | 0.1 | (4.9) | 9.4 | - | 9.4 | 13.0 |
| 101. | Regulatory Overheads | 64.3 | 15.8 | (9.8) | 70.3 | - | 70.3 | 69.4 |
| 102. | Sub-total | 418.6 | 97.4 | (96.5) | 419.5 | - | 419.5 | 437.6 |
| 103. | Union Rate Zones Total | 10,573.6 | 647.9 | (118.3) | 11,103.2 | - | 11,103.2 | 10,733.8 |
| 104. | EGI Total | 21,264.7 | 1,193.2 | (247.4) | 22,210.5 | (4.8) | 22,205.7 | 21,522.4 |

EGI UTILITY PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

| Line No. | | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 |
|--|--|--------------------------|--------------|--------------|-----------------------|--------------------------|-----------------------|--------------------------|-----------------------------|
| | | Opening Balance Dec.2020 | Additions | Retirements | Costs Net of Proceeds | Closing Balance Dec.2021 | Regulatory Adjustment | Utility Balance Dec.2021 | Average of Monthly Averages |
| | | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) |
| EGD Rate Zone Underground Storage Plant | | | | | | | | | |
| 1. | Land and gas storage rights (451) | (26.6) | (0.5) | - | - | (27.1) | - | (27.1) | (26.8) |
| 2. | Structures and improvements (452) | (2.3) | (0.6) | - | - | (2.9) | 0.1 | (2.8) | (2.5) |
| 3. | Wells (453) | (14.3) | (1.2) | - | - | (15.5) | - | (15.5) | (14.8) |
| 4. | Well equipment (454) | (7.8) | (0.8) | - | - | (8.6) | - | (8.6) | (8.1) |
| 5. | Field Lines (455) | (32.2) | (1.8) | - | - | (34.0) | - | (34.0) | (33.1) |
| 6. | Compressor equipment (456) | (53.2) | (4.5) | - | - | (57.7) | 0.3 | (57.4) | (55.0) |
| 7. | Measuring and regulating equipment (457) | (7.9) | (0.3) | - | - | (8.3) | - | (8.3) | (8.1) |
| 8. | Sub-Total | (144.2) | (9.7) | - | - | (154.0) | 0.3 | (153.6) | (148.5) |
| EGD Rate Zone Distribution Plant | | | | | | | | | |
| 9. | Renewable Natural Gas (461) | - | - | - | - | - | - | - | - |
| 10. | Land rights intangibles (471) | (5.7) | (0.8) | - | - | (6.5) | - | (6.5) | (6.1) |
| 11. | Structures and improvements (472) | (42.9) | (10.2) | 4.7 | - | (48.3) | 0.3 | (48.0) | (42.7) |
| 12. | Services, house reg & meter install. (473/474) | (1,104.3) | (76.4) | 9.9 | 28.4 | (1,142.4) | - | (1,142.4) | (1,126.2) |
| 13. | Mains (475) | (1,295.9) | (109.4) | (73.5) | 16.9 | (1,461.9) | 2.2 | (1,459.7) | (1,322.2) |
| 14. | NGV station compressors (476) | (3.3) | (0.3) | - | - | (3.6) | - | (3.6) | (3.4) |
| 15. | Measuring and regulating equip. (477) | (252.4) | (15.1) | 8.8 | 0.7 | (257.9) | 0.5 | (257.4) | (254.4) |
| 16. | Meters (478) | (303.2) | (41.0) | 21.3 | 0.0 | (323.0) | - | (323.0) | (315.7) |
| 17. | Sub-Total | (3,007.7) | (253.1) | (28.9) | 46.1 | (3,243.6) | 3.0 | (3,240.5) | (3,070.8) |
| EGD Rate Zone General Plant | | | | | | | | | |
| 18. | Lease improvements (482) | (0.1) | 0.0 | - | - | (0.1) | 0.2 | 0.1 | 0.1 |
| 19. | Office furniture and equipment (483) | (12.6) | (1.9) | - | - | (14.4) | - | (14.4) | (13.4) |
| 20. | Transportation equipment (484) | (32.2) | (5.3) | 1.4 | (0.1) | (36.3) | 0.1 | (36.3) | (33.7) |
| 21. | NGV conversion kits (484) | 0.4 | (0.3) | - | - | 0.2 | - | 0.2 | 0.3 |
| 22. | Heavy work equipment (485) | (6.0) | (0.6) | - | - | (6.6) | - | (6.6) | (6.3) |
| 23. | Tools and work equipment (486) | (22.3) | (1.9) | - | - | (24.1) | - | (24.1) | (23.0) |
| 24. | Rental equipment (487) | (1.1) | 0.0 | - | - | (1.1) | - | (1.1) | (1.1) |
| 25. | NGV rental compressors (487) | (2.7) | 0.2 | - | - | (2.4) | - | (2.4) | (3.3) |
| 26. | NGV cylinders (484 and 487) | (0.5) | (0.0) | - | - | (0.5) | - | (0.5) | (0.5) |
| 27. | Communication structures & equip. (488) | (1.4) | (0.2) | 1.8 | - | 0.1 | - | 0.1 | (0.6) |
| 28. | Computer equipment (490) | (31.6) | (1.9) | 7.2 | - | (26.4) | - | (26.4) | (29.8) |
| 29. | Software Aquired/Developed (491) | (229.9) | (6.9) | 23.5 | - | (213.3) | - | (213.3) | (230.5) |
| 30. | CIS (491) | (127.1) | (18.3) | 124.1 | - | (21.3) | - | (21.3) | (109.9) |
| 31. | WAMS (489) | (38.4) | (8.1) | - | - | (46.4) | - | (46.4) | (42.0) |
| 32. | Sub-Total | (505.5) | (45.2) | 158.0 | (0.1) | (392.7) | 0.3 | (392.5) | (493.6) |
| EGD Rate Zone Plant held for future use | | | | | | | | | |
| 33. | Inactive services (102) | (1.4) | (0.0) | - | - | (1.4) | - | (1.4) | (1.4) |
| 34. | EGD Rate Zone Total | (3,658.8) | (308.0) | 129.1 | 46.0 | (3,791.7) | 3.6 | (3,788.1) | (3,714.3) |
| Union Rate Zones Intangible Plant | | | | | | | | | |
| 35. | Franchises and consents (401) | (0.9) | (0.1) | - | - | (1.0) | - | (1.0) | (1.0) |
| 36. | Other intangible plant (402) | (0.3) | (0.2) | - | - | (0.5) | - | (0.5) | (0.3) |
| 37. | Sub-Total | (1.2) | (0.3) | - | - | (1.5) | - | (1.5) | (1.3) |

Union Rate Zones Local Storage Plant

| | | | | | | | | | |
|-----|-----------------------------------|--------|-------|---|-----|--------|---|--------|--------|
| 38. | Structures and improvements (442) | (2.7) | (0.1) | - | 0.2 | (2.7) | - | (2.7) | (2.7) |
| 39. | Gas holders - storage (443) | (3.8) | (0.1) | - | - | (3.9) | - | (3.9) | (3.9) |
| 40. | Gas holders - equipment (443) | (10.3) | (0.7) | - | 0.0 | (11.0) | - | (11.0) | (10.6) |
| 41. | Regulatory Overheads | (0.5) | (0.1) | - | - | (0.6) | - | (0.6) | (0.5) |
| 42. | Sub-Total | (17.3) | (1.0) | - | 0.2 | (18.2) | - | (18.2) | (17.8) |

Union Rate Zones Underground Storage Plant

| | | | | | | | | | |
|-----|--|---------|--------|---|-----|---------|---|---------|---------|
| 43. | Land rights (451) | (18.1) | (0.7) | - | - | (18.8) | - | (18.8) | (18.4) |
| 44. | Structures and improvements (452) | (42.1) | (1.7) | - | - | (43.9) | - | (43.9) | (43.0) |
| 45. | Wells (453) | (33.0) | (1.2) | - | - | (34.2) | - | (34.2) | (33.6) |
| 46. | Field Lines (455) | (28.4) | (1.2) | - | - | (29.6) | - | (29.6) | (29.1) |
| 47. | Compressor equipment (456) | (155.6) | (12.6) | - | 0.0 | (168.2) | - | (168.2) | (161.9) |
| 48. | Measuring & regulating equipment (457) | (44.3) | 1.2 | - | 0.1 | (43.0) | - | (43.0) | (45.4) |
| 49. | Regulatory Overheads | (3.6) | (0.5) | - | - | (4.1) | - | (4.1) | (4.0) |
| 50. | Sub-Total | (325.1) | (16.7) | - | 0.1 | (341.7) | - | (341.7) | (335.4) |

Union Rate Zones Transmission Plant

| | | | | | | | | | |
|-----|---|-----------|--------|-----|-----|-----------|---|-----------|-----------|
| 51. | Land rights (461) | (18.1) | (1.2) | - | - | (19.3) | - | (19.3) | (18.7) |
| 52. | Structures & improvements (462/463/464) | (43.5) | (3.4) | - | 0.1 | (46.8) | - | (46.8) | (45.1) |
| 53. | Mains (465) | (662.8) | (38.9) | 4.1 | 0.4 | (697.3) | - | (697.3) | (682.0) |
| 54. | Compressor equipment (466) | (293.9) | (30.5) | - | 0.0 | (324.3) | - | (324.3) | (309.1) |
| 55. | Measuring & regulating equipment (467) | (104.0) | (12.2) | - | 0.0 | (116.2) | - | (116.2) | (108.4) |
| 56. | Regulatory Overheads | (22.8) | (5.2) | - | - | (28.0) | - | (28.0) | (25.3) |
| 57. | Sub-Total | (1,145.1) | (91.4) | 4.1 | 0.5 | (1,231.9) | - | (1,231.9) | (1,188.6) |

Union Rate Zones Distribution Plant - Southern Operations

| | | | | | | | | | |
|-----|--|-----------|--------|------|-------|-----------|---|-----------|-----------|
| 58. | Land rights (471) | (2.3) | (0.1) | - | - | (2.4) | - | (2.4) | (2.3) |
| 59. | Structures and improvements (472) | (44.3) | (3.1) | - | 0.0 | (47.4) | - | (47.4) | (45.8) |
| 60. | Services - metallic (473) | (107.3) | (3.6) | 0.3 | 1.8 | (108.8) | - | (108.8) | (108.7) |
| 61. | Services - plastic (473) | (428.6) | (24.5) | 1.8 | 6.8 | (444.5) | - | (444.5) | (437.2) |
| 62. | Regulators (474) | (41.7) | (4.8) | 5.8 | - | (40.8) | - | (40.8) | (43.1) |
| 63. | House regulators & meter installations (474) | (30.1) | (2.2) | - | 0.0 | (32.3) | - | (32.3) | (31.2) |
| 64. | Mains - metallic (475) | (363.6) | (16.8) | 0.9 | 3.6 | (375.9) | - | (375.9) | (370.5) |
| 65. | Mains - plastic (475) | (285.4) | (16.6) | 0.5 | 0.5 | (300.9) | - | (300.9) | (293.3) |
| 66. | Measuring & regulating equipment (477) | (21.5) | (2.4) | - | 0.3 | (23.6) | - | (23.6) | (22.4) |
| 67. | Meters (478) | (106.8) | (14.5) | 3.3 | (0.1) | (118.0) | - | (118.0) | (112.0) |
| 68. | Regulatory Overheads | (44.5) | (9.4) | - | - | (53.9) | - | (53.9) | (48.9) |
| 69. | Sub-Total | (1,476.1) | (98.1) | 12.7 | 13.1 | (1,548.5) | - | (1,548.5) | (1,515.5) |

Union Rate Zones Distribution Plant - Northern & Eastern Operations

| | | | | | | | | | |
|-----|--|---------|--------|-----|-------|-----------|---|-----------|---------|
| 70. | Land rights intangibles (471) | (4.3) | (0.2) | - | - | (4.5) | - | (4.5) | (4.4) |
| 71. | Structures and improvements (472) | (26.7) | (1.7) | - | - | (28.3) | - | (28.3) | (27.5) |
| 72. | Services - metallic (473) | (78.6) | (3.6) | 0.2 | 0.5 | (81.4) | - | (81.4) | (80.2) |
| 73. | Services - plastic (473) | (219.0) | (12.9) | 0.8 | 0.4 | (230.7) | - | (230.7) | (225.3) |
| 74. | Regulators (474) | (15.6) | (1.8) | 2.1 | (0.0) | (15.3) | - | (15.3) | (16.1) |
| 75. | House regulators & meter installations (474) | (16.5) | (1.2) | - | 0.0 | (17.7) | - | (17.7) | (17.1) |
| 76. | Mains - metallic (475) | (348.4) | (20.7) | 0.8 | 1.5 | (366.9) | - | (366.9) | (358.3) |
| 77. | Mains - plastic (475) | (114.2) | (5.7) | 0.2 | 0.0 | (119.6) | - | (119.6) | (117.0) |
| 78. | Measuring & regulating equipment (477) | (77.3) | (5.7) | - | 0.3 | (82.7) | - | (82.7) | (80.0) |
| 79. | Meters (478) | (25.5) | (3.9) | 0.9 | 0.0 | (28.6) | - | (28.6) | (26.9) |
| 80. | Regulatory Overheads | (24.8) | (5.2) | - | - | (30.0) | - | (30.0) | (27.3) |
| 81. | Sub-Total | (950.9) | (62.7) | 5.0 | 2.7 | (1,005.9) | - | (1,005.9) | (980.1) |

Union Rate Zones General Plant

| | | | | | | | | | |
|-----|--------------------------------------|-----------|---------|-------|-------|-----------|-----|-----------|-----------|
| 82. | Structures & improvements (482) | (15.7) | (1.6) | - | - | (17.3) | - | (17.3) | (16.5) |
| 83. | Office furniture and equipment (483) | (6.4) | (0.7) | 0.9 | 0.0 | (6.2) | - | (6.2) | (6.6) |
| 84. | Office equipment - computers (483) | (90.5) | (25.2) | 69.1 | - | (46.6) | - | (46.6) | (96.3) |
| 85. | Transportation equipment (484) | (48.1) | (8.7) | 5.1 | (1.2) | (52.8) | - | (52.8) | (50.8) |
| 86. | Heavy work equipment (485) | (5.3) | (1.3) | 0.5 | - | (6.2) | - | (6.2) | (5.8) |
| 87. | Tools and work equipment (486) | (20.8) | (2.4) | 6.1 | - | (17.2) | - | (17.2) | (21.1) |
| 88. | NGV fuel equipment (487) | (1.4) | (0.1) | - | - | (1.6) | - | (1.6) | (1.5) |
| 89. | Communication equipment (488) | (9.4) | (0.7) | 4.9 | - | (5.1) | - | (5.1) | (8.5) |
| 90. | Regulatory Overheads | (31.0) | (6.3) | 9.8 | - | (27.5) | - | (27.5) | (33.9) |
| 91. | Sub-Total | (228.7) | (47.1) | 96.5 | (1.2) | (180.5) | - | (180.5) | (241.0) |
| 92. | Union Rate Zones Total | (4,144.3) | (317.4) | 118.3 | 15.4 | (4,328.1) | - | (4,328.1) | (4,279.7) |
| 93. | EGI Total | (7,803.2) | (625.4) | 247.4 | 61.4 | (8,119.8) | 3.6 | (8,116.2) | (7,994.0) |

EGI WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 |
|---------------------------|------------------------|----------------|----------------------------|------------------|---------------|----------------|------------------------|--------------|
| Line No. | Materials and Supplies | ABC Receivable | Customer Security Deposits | Prepaid Expenses | Balancing Gas | Gas in Storage | Working Cash Allowance | Total |
| | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) | (\$Millions) |
| 1. January 1 | 87.5 | (14.7) | (78.3) | (0.4) | 59.5 | 657.3 | 20.9 | 731.8 |
| 2. January 31 | 88.2 | (9.5) | (71.3) | (11.0) | 59.5 | 558.1 | 20.9 | 634.7 |
| 3. February | 88.6 | (15.2) | (71.2) | (4.0) | 59.5 | 426.1 | 20.9 | 504.6 |
| 4. March | 89.8 | (34.9) | (71.3) | 3.7 | 59.5 | 325.3 | 20.9 | 392.8 |
| 5. April | 92.4 | (26.5) | (71.2) | 7.0 | 59.5 | 308.0 | 20.9 | 389.9 |
| 6. May | 92.8 | (25.6) | (72.4) | 6.7 | 59.5 | 360.6 | 20.9 | 442.4 |
| 7. June | 94.4 | (31.1) | (66.2) | 7.5 | 59.5 | 475.2 | 20.9 | 560.1 |
| 8. July | 95.7 | (15.3) | (66.6) | 4.0 | 59.5 | 569.9 | 20.9 | 668.0 |
| 9. August | 98.4 | (9.2) | (66.7) | 9.0 | 59.5 | 664.2 | 20.9 | 776.0 |
| 10. September | 91.9 | (12.2) | (66.0) | 11.8 | 59.5 | 762.0 | 20.9 | 867.8 |
| 11. October | 93.4 | 2.2 | (65.8) | 13.3 | 59.5 | 984.0 | 20.9 | 1,107.4 |
| 12. November | 94.8 | 3.5 | (65.9) | 8.6 | 59.5 | 926.4 | 20.9 | 1,047.7 |
| 13. December | 91.4 | (10.0) | (65.1) | (0.8) | 59.5 | 895.1 | 20.9 | 990.9 |
| 14. Avg. of monthly avgs. | 92.5 | (15.5) | (68.9) | 4.7 | 59.5 | 594.7 | 20.9 | 687.7 |

EGI SUMMARY OF CAPITAL STRUCTURE & COST OF CAPITAL
2021 ACTUAL

| Line No. | Col. 1 | | Col. 2 | Col. 3 | Col. 4 | Col. 5 (Col. 1x Col. 3) |
|------------------------------|---------------------------|-----------|-----------|---------------------|----------------------|----------------------------|
| | Utility Capital Structure | | Cost Rate | Return Component | Interest & Return | |
| | Principal | Component | | | | |
| | (\$Millions) | % | % | % | (\$Millions) | |
| 1. Long and Medium-Term Debt | 8,505.3 | 59.83 | 4.37 | 2.612 | 371.3 | |
| 2. Short-Term Debt | 593.1 | 4.17 | 0.31 | 0.013 | 1.9 | |
| 3. Total Debt | 9,098.3 | 64.00 | | 2.625 | | |
| 4. Preference Shares | - | - | - | - | - | |
| 5. Common Equity | 5,117.8 | 36.00 | 9.84 | 3.542 | 503.6 | |
| 6. Total Rate Base | 14,216.1 | 100.00 | | 6.167 | 876.7 | |

CALCULATION OF COST RATES
FOR EGI CAPITAL STRUCTURE COMPONENTS
2021 ACTUAL

| Line No. | | Col. 1 Average of Monthly Averages (\$Millions) | Col. 2 | Col. 3 Carrying Cost (\$Millions) |
|-------------|--|---|--------------|--|
| | <u>Long and Medium-Term Debt</u> | | | |
| 1. | Debt Summary | 8,833.5 | | 381.1 |
| 2. | Unamortized Finance Costs | (103.3) | | - |
| 3. | (Profit)/Loss on Redemption | - | | - |
| 4. | | <u>8,730.2</u> | | <u>381.1</u> |
| 5. | Percentage Allocation of Debt to Unregulated 2.58% | <u>(224.9)</u> | | <u>(9.8)</u> |
| 6. | Net Regulated Long and Medium-Term Debt | <u>8,505.3</u> | | <u>371.3</u> |
| 7. | Calculated Cost Rate | | <u>4.37%</u> | |
| | <u>Short-Term Debt</u> | | | |
| 8. | Calculated Cost Rate | | <u>0.31%</u> | |
| | <u>Preference Shares</u> | | | |
| 9. | Preference Share Summary | - | | - |
| 10. | Unamortized Finance Costs | - | | - |
| 11. | (Profit)/Loss on Redemption | - | | - |
| 12. | | <u>-</u> | | <u>-</u> |
| 13. | Calculated Cost Rate | | <u>0.00%</u> | |
| | <u>Common Equity</u> | | | |
| 14. | Board Formula ROE | | 8.34% | |
| 15. | Threshold before earnings sharing | | <u>1.50%</u> | |
| 16. | ROE for earnings sharing determination | | <u>9.84%</u> | |

EGI SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2021 ACTUAL

| | | | Col. 1 | Col. 2 | Col. 3 |
|----------------------|-----------------|--------------------|------------------|-----------|----------------|
| Line | Coupon | | Average of | Effective | Carrying |
| No. | Rate | Maturity Date | Monthly Averages | Cost Rate | Cost |
| | | | Principal | | |
| | | | (\$Millions) | | (\$Millions) |
| Medium Term Notes | | | | | |
| 1. | 8.85% | October 2, 2025 | 20.0 | 8.97% | 1.8 |
| 2. | 7.60% | October 29, 2026 | 100.0 | 8.09% | 8.1 |
| 3. | 6.65% | November 3, 2027 | 100.0 | 6.71% | 6.7 |
| 4. | 6.10% | May 19, 2028 | 100.0 | 6.16% | 6.2 |
| 5. | 6.05% | July 5, 2023 | 100.0 | 6.38% | 6.4 |
| 6. | 6.90% | November 15, 2032 | 150.0 | 6.95% | 10.4 |
| 7. | 6.16% | December 16, 2033 | 150.0 | 6.18% | 9.3 |
| 8. | 5.21% | February 25, 2036 | 300.0 | 5.18% | 15.5 |
| 9. | 4.77% | December 17, 2021 | 167.7 | 5.31% | 8.9 |
| 10. | 4.95% | November 22, 2050 | 200.0 | 4.99% | 10.0 |
| 11. | 4.95% | November 22, 2050 | 100.0 | 4.73% | 4.7 |
| 12. | 4.50% | November 23, 2043 | 200.0 | 4.20% | 8.4 |
| 13. | 3.15% | August 22, 2024 | 215.0 | 3.24% | 7.0 |
| 14. | 4.00% | August 22, 2044 | 215.0 | 3.89% | 8.4 |
| 15. | 4.00% | August 22, 2044 | 170.0 | 4.44% | 7.5 |
| 16. | 3.31% | September 11, 2025 | 400.0 | 3.62% | 14.5 |
| 17. | 2.50% | August 5, 2026 | 300.0 | 3.42% | 10.3 |
| 18. | 3.51% | November 29, 2047 | 300.0 | 3.53% | 10.6 |
| 19. | 2.37% | August 9, 2029 | 400.0 | 3.23% | 12.9 |
| 20. | 3.01% | August 9, 2049 | 300.0 | 3.03% | 9.1 |
| 21. | 2.90% | April 1, 2030 | 600.0 | 3.41% | 20.4 |
| 22. | 3.65% | April 1, 2050 | 600.0 | 3.67% | 22.0 |
| 23. | 2.35% | September 1, 2031 | 138.5 | 2.94% | 4.1 |
| 24. | 3.20% | September 1, 2051 | 124.0 | 3.22% | 4.0 |
| 25. | 8.65% | November 10, 2025 | 125.0 | 8.77% | 11.0 |
| 26. | 5.46% | September 11, 2036 | 165.0 | 5.49% | 9.1 |
| 27. | 4.85% | April 25, 2022 | 125.0 | 4.91% | 6.1 |
| 28. | 6.05% | September 2, 2038 | 300.0 | 6.10% | 18.3 |
| 29. | 5.20% | July 23, 2040 | 250.0 | 5.27% | 13.2 |
| 30. | 4.88% | June 21, 2041 | 300.0 | 4.92% | 14.8 |
| 31. | 3.79% | July 10, 2023 | 250.0 | 3.87% | 9.7 |
| 32. | 2.76% | June 2, 2021 | 83.3 | 2.85% | 2.4 |
| 33. | 4.20% | June 2, 2044 | 250.0 | 4.24% | 10.6 |
| 34. | 4.20% | June 2, 2044 | 250.0 | 4.27% | 10.7 |
| 35. | 3.19% | September 17, 2025 | 200.0 | 3.26% | 6.5 |
| 36. | 2.81% | June 1, 2026 | 250.0 | 2.87% | 7.2 |
| 37. | 3.80% | June 1, 2046 | 250.0 | 3.84% | 9.6 |
| 38. | 3.59% | November 22, 2047 | 250.0 | 3.64% | 9.1 |
| 39. | 2.88% | November 22, 2027 | 250.0 | 2.95% | 7.4 |
| 40. | | | 8,748.5 | | 372.7 |
| Long-Term Debentures | | | | | |
| 41. | 9.85% | December 2, 2024 | 85.0 | 9.910% | 8.4 |
| 42. | | | 85.0 | | 8.4 |
| 43. | Total Term Debt | | 8,833.5 | | 381.1 |

EGI UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

| | | Col. 1 |
|------|-----------------------------|------------------------------|
| Line | | Unamortized |
| No. | | Debt Discount and Expense |
| | | (\$Millions) |
| 1. | January 1 | 100.9 |
| 2. | January 31 | 99.8 |
| 3. | February | 98.8 |
| 4. | March | 97.7 |
| 5. | April | 96.7 |
| 6. | May | 95.6 |
| 7. | June | 94.6 |
| 8. | July | 93.5 |
| 9. | August | 92.5 |
| 10. | September | 121.8 |
| 11. | October | 120.5 |
| 12. | November | 119.2 |
| 13. | December | 118.1 |
| 14. | Average of Monthly Averages | <u>103.3</u> |

RECONCILIATION OF AUDITED EGI INCOME (PER FINANCIAL STATEMENTS)
TO CORPORATE INCOME FOR UTILITY INCOME DETERMINATION PURPOSES
2021 ACTUAL

| Line no. | (\$ millions) | Col. 1 Audited Income (as per Financial Statements) | Col. 2 Corporate Income (as per Utility Income Schedule) | Col. 3 Variance | Col. 4 Reference |
|----------|---|---|--|--------------------|---------------------|
| | Operating Revenues | | | | |
| 1. | Gas sales and distribution | 3,996.4 | 4,513.2 | | |
| 2. | Storage, transportation and other | 896.7 | - | | |
| 3. | Transportation | - | 143.0 | | |
| 4. | Storage | - | 159.7 | | |
| 5. | Other operating revenue | - | 64.3 | | |
| 6. | Other Income | 42.9 | 7.2 | | |
| 7. | Total operating revenue | 4,936.0 | 4,887.4 | (48.6) | (a) |
| | Operating Expenses | | | | |
| 8. | Gas Costs | 2,146.2 | 2,146.2 | - | |
| 9. | Operation and maintenance | 1,105.1 | 938.6 | (166.5) | (b) |
| 10. | Depreciation and amortization expense | 676.8 | 676.8 | - | |
| 11. | Fixed financing costs | - | 6.3 | 6.3 | (c) |
| 12. | Municipal and other taxes | - | 117.9 | 117.9 | (d) |
| 13. | Cost of service | 3,928.1 | 3,885.8 | (42.3) | |
| 14. | Income before interest and income taxes | 1,007.9 | 1,001.6 | (6.3) | |
| 15. | Interest and financing expenses | 393.9 | - | (393.9) | (e) |
| 16. | Income before income taxes | 614.0 | 1,001.6 | 387.6 | |
| 17. | Income taxes | 62.9 | - | (62.9) | (f) |
| 18. | Net Income | 551.1 | 1,001.6 | 450.5 | |

Col. 2 - Corporate income as reported in Exhibit B, Tab 1, Schedule 2, Column 1

| | |
|--|----------------|
| a) Audited Total Operating Revenue | 4,936.0 |
| Reclassify pension related other revenue to O&M | (36.0) |
| Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue | (12.8) |
| Reclassify other expenses out of other income to O&M | 0.2 |
| Corporate Total Operating Revenue | <u>4,887.4</u> |
| b) Audited Operation and Maintenance | 1,105.1 |
| Reclassify pension related other revenue to O&M | (36.0) |
| Reclassify Municipal & Property Taxes out of O&M | (117.9) |
| Reclassify EGD rate zone Open Bill and ABC T-service O&M against program revenues in other revenue | (12.8) |
| Reclassify other expenses out of other income to O&M | 0.2 |
| Corporate Operation and Maintenance | <u>938.6</u> |
| c) Audited Fixed Financing Costs | - |
| Reclassify fixed financing costs from interest and financing expenses | 6.3 |
| Corporate Fixed Financing Costs | <u>6.3</u> |
| d) Audited Municipal and Other Taxes | - |
| Reclassify Municipal and other taxes included within O&M costs | 117.9 |
| Corporate Municipal and Other Taxes | <u>117.9</u> |
| e) Audited Interest and Financing expenses | 393.9 |
| Reclassify fixed financing costs from interest and financing expenses | (6.3) |
| Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure | (387.6) |
| Corporate Interest and Financing expenses | <u>-</u> |
| f) Audited Income Taxes | 62.9 |
| Elimination of corporate income taxes which will be calculated on a utility stand-alone basis | (62.9) |
| Corporate Income Taxes | <u>-</u> |

DELIVERY REVENUE BY SERVICE TYPE, RATE CLASS AND SERVICE CLASS
ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2021

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 |
|--|---------------------------|--------------|---------------|--------------|--------------|----------------|
| | Revenues (\$ Millions) | | | | | |
| Line No. | Sales | ABC-T | ABC-Unbundled | Bundled-T | T-Service | Total |
| 1 <u>General Service</u> | | | | | | |
| 2 Rate 1 | 920.6 | 16.4 | 0.0 | (0.0) | 0.0 | 937.0 |
| 3 Rate 6 | 288.5 | 78.0 | 0.0 | 28.4 | 0.0 | 394.9 |
| 4 Rate 9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 5 Total EGD Rate Zone | 1,209.1 | 94.4 | 0.0 | 28.4 | 0.0 | 1,331.8 |
| 6 Rate M1 | 463.7 | 16.9 | 0.0 | 1.4 | 0.0 | 482.0 |
| 7 Rate M2 | 33.0 | 20.7 | 0.0 | 14.2 | 0.0 | 67.9 |
| 8 Rate 01 | 173.9 | 7.4 | 0.0 | 0.9 | 0.0 | 182.2 |
| 9 Rate 10 | 10.5 | 5.8 | 0.0 | 4.4 | 0.2 | 21.0 |
| 10 Total Union Rate Zones | 681.1 | 50.9 | 0.0 | 20.9 | 0.2 | 753.1 |
| 11 Total General Service | 1,890.2 | 145.3 | 0.0 | 49.3 | 0.2 | 2,084.9 |
| 12 <u>Wholesale - Utility</u> | | | | | | |
| 13 Rate M9 | 0.7 | 0.0 | 0.0 | 1.0 | 0.0 | 1.7 |
| 14 Rate M10 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 15 Total Wholesale - Utility | 0.7 | 0.0 | 0.0 | 1.0 | 0.0 | 1.7 |
| 16 <u>Contract Sales</u> | | | | | | |
| 17 Rate 100 | 0.6 | 0.3 | 0.0 | 1.1 | 0.0 | 2.0 |
| 18 Rate 110 | 2.6 | 4.6 | 0.0 | 24.0 | 0.0 | 31.2 |
| 19 Rate 115 | 0.0 | 0.0 | 0.0 | 5.4 | 0.0 | 5.4 |
| 20 Rate 125 | 0.0 | 0.0 | 0.0 | 0.0 | 11.9 | 11.9 |
| 21 Rate 135 | 0.2 | 0.2 | 0.0 | 1.2 | 0.0 | 1.5 |
| 22 Rate 145 | 0.0 | 0.1 | 0.0 | 1.5 | 0.0 | 1.7 |
| 23 Rate 170 | 0.1 | 0.2 | 0.0 | 2.6 | 0.0 | 2.9 |
| 24 Rate 200 | 3.2 | 0.0 | 0.0 | 1.6 | 0.0 | 4.9 |
| 25 Rate 300 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 |
| 26 Rate 315 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 27 Total EGD Rate Zone | 6.7 | 5.4 | 0.0 | 37.4 | 11.9 | 61.5 |
| 28 Rate M4 | 4.0 | 2.3 | 0.0 | 26.5 | 0.0 | 32.8 |
| 29 Rate M7 | 2.3 | 0.5 | 0.0 | 20.7 | 0.0 | 23.4 |
| 30 Rate 20 | 0.8 | 0.1 | 0.0 | 3.0 | 20.7 | 24.7 |
| 31 Rate 100 | 0.0 | 0.0 | 0.0 | 0.0 | 11.5 | 11.5 |
| 32 Rate T-1 | 0.0 | 0.0 | 0.0 | 0.0 | 13.9 | 13.9 |
| 33 Rate T-2 | 0.0 | 0.0 | 0.0 | 0.0 | 75.9 | 75.9 |
| 34 Rate T-3 | 0.0 | 0.0 | 0.0 | 0.0 | 7.2 | 7.2 |
| 35 Rate M5 | 0.2 | 0.2 | 0.0 | 2.2 | 0.0 | 2.5 |
| 36 Rate 25 | 2.7 | 0.0 | 0.0 | 0.4 | 2.7 | 5.8 |
| 37 Rate 30 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 38 Total Union Rate Zones | 9.9 | 3.1 | 0.0 | 52.8 | 131.9 | 197.7 |
| 39 Total Contract Sales | 16.6 | 8.5 | 0.0 | 90.3 | 143.9 | 259.2 |
| 40 Subtotal | 1,907.5 | 153.8 | 0.0 | 140.6 | 144.1 | 2,345.9 |
| 41 Accounting Adjustments: | | | | | | |
| 42 EGI Tax Variance | | | | | | (18.0) |
| 43 EGI Accounting Policy Change | | | | | | (16.2) |
| 44 EGD Average Use / Normalized Average Consumption | | | | | | 9.9 |
| 45 EGD Dawn Access COS (DACDA) | | | | | | 2.0 |
| 46 EGD Incremental Capital Module | | | | | | 0.2 |
| 47 EGD LRAM | | | | | | 0.0 |
| 48 EGD Federal Carbon Program | | | | | | 0.7 |
| 49 EGD Greenhouse Gas Emissions Administration | | | | | | 0.1 |
| 50 Union Average Use / Normalized Average Consumption | | | | | | 16.0 |
| 51 Union Incremental Capital Module | | | | | | (14.0) |
| 52 Union Capital Pass-through | | | | | | (4.4) |
| 53 Union LRAM | | | | | | 0.7 |
| 54 Union Federal Carbon Program | | | | | | 1.5 |
| 55 Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues | | | | | | (17.2) |
| Total Utility Revenue | | | | | | 2,307.3 |

DELIVERY REVENUE BY SERVICE TYPE, RATE CLASS AND SERVICE CLASS

ENBRIDGE GAS INC.

FOR THE YEAR ENDED DECEMBER 31, 2020

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 |
|----------|---|----------------|---------------|--------------|-------------|----------------|
| | Revenues (\$ Millions) | | | | | |
| Line No. | Sales | ABC-T | ABC-Unbundled | Bundled-T | T-Service | Total |
| 1 | <u>General Service</u> | | | | | |
| 2 | Rate 1 | 912.6 | 19.9 | 0.0 | 0.0 | 932.6 |
| 3 | Rate 6 | 284.9 | 81.3 | 0.0 | 0.0 | 394.6 |
| 4 | Rate 9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 5 | Total EGD Rate Zone | 1,197.5 | 101.2 | 0.0 | 0.0 | 1,327.3 |
| 6 | Rate M1 | 448.2 | 18.7 | (0.0) | 1.3 | 468.1 |
| 7 | Rate M2 | 33.5 | 21.2 | 0.0 | 14.3 | 69.0 |
| 8 | Rate O1 | 171.7 | 8.5 | 0.0 | 1.0 | 181.2 |
| 9 | Rate 10 | 10.7 | 6.1 | 0.0 | 5.2 | 22.4 |
| 10 | Total Union Rate Zones | 664.1 | 54.5 | (0.0) | 21.8 | 740.7 |
| 11 | Total General Service | 1,861.6 | 155.7 | (0.0) | 21.8 | 2,068.0 |
| 12 | <u>Wholesale - Utility</u> | | | | | |
| 13 | Rate M9 | 0.6 | 0.0 | 0.0 | 0.9 | 1.6 |
| 14 | Rate M10 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 15 | Total Wholesale - Utility | 0.7 | 0.0 | 0.0 | 0.9 | 1.6 |
| 16 | <u>Contract Sales</u> | | | | | |
| 17 | Rate 100 | 0.6 | 0.2 | 0.0 | 0.0 | 1.5 |
| 18 | Rate 110 | 2.6 | 2.8 | 0.0 | 0.0 | 26.5 |
| 19 | Rate 115 | 0.3 | 0.0 | 0.0 | 0.0 | 5.4 |
| 20 | Rate 125 | 0.0 | 0.0 | 11.5 | 0.0 | 11.5 |
| 21 | Rate 135 | 0.1 | 0.1 | 0.0 | 0.0 | 1.3 |
| 22 | Rate 145 | 0.0 | 0.1 | 0.0 | 0.0 | 1.1 |
| 23 | Rate 170 | 0.1 | 0.2 | 0.0 | 0.0 | 2.5 |
| 24 | Rate 200 | 3.1 | 0.0 | 0.0 | 0.0 | 4.5 |
| 25 | Rate 300 | 0.0 | 0.0 | 0.1 | 0.0 | 0.1 |
| 26 | Rate 315 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 27 | Total EGD Rate Zone | 6.7 | 3.4 | 11.6 | 0.0 | 54.4 |
| 28 | Rate M4 | 3.5 | 1.7 | 0.0 | 26.4 | 31.6 |
| 29 | Rate M7 | 1.6 | 0.3 | 0.0 | 16.8 | 18.8 |
| 30 | Rate 20 Storage | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 31 | Rate 20 Transportation | 0.9 | 0.1 | 0.0 | 2.7 | 25.0 |
| 32 | Rate 100 Storage | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 33 | Rate 100 Transportation | 0.0 | 0.0 | 0.0 | 0.0 | 11.3 |
| 34 | Rate T-1 Storage | 0.0 | 0.0 | 0.0 | 0.0 | 1.4 |
| 35 | Rate T-1 Transportation | 0.0 | 0.0 | 0.0 | 0.0 | 12.2 |
| 36 | Rate T-2 Storage | 0.0 | 0.0 | 0.0 | 0.0 | 7.2 |
| 37 | Rate T-2 Transportation | 0.0 | 0.0 | 0.0 | 0.0 | 66.9 |
| 38 | Rate T-3 Storage | 0.0 | 0.0 | 0.0 | 0.0 | 1.4 |
| 39 | Rate T-3 Transportation | 0.0 | 0.0 | 0.0 | 0.0 | 5.8 |
| 40 | Rate M5 | 0.1 | 0.1 | 0.0 | 2.0 | 2.3 |
| 41 | Rate 25 | 1.1 | 0.0 | 0.0 | 0.0 | 3.8 |
| 42 | Rate 30 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 43 | Total Union Rate Zones | 7.3 | 2.3 | 0.0 | 47.9 | 187.6 |
| 44 | Total Contract Sales | 14.0 | 5.7 | 11.6 | 47.9 | 241.9 |
| 45 | Subtotal | 1,876.3 | 161.4 | 11.6 | 70.7 | 2,311.5 |
| 46 | Accounting Adjustments: | | | | | |
| 47 | EGI Tax Variance | | | | | (13.4) |
| 48 | EGI Accounting Policy Change | | | | | (14.0) |
| 49 | EGD Average Use/ Normalized Average Consumption | | | | | (2.5) |
| 50 | EGD Dawn Access Cost | | | | | 2.1 |
| 51 | EGD Incremental Capital Module | | | | | (0.3) |
| 52 | EGD Transactional Services Revenue | | | | | 12.0 |
| 53 | EGD LRAM | | | | | 0.0 |
| 54 | EGD Federal Carbon Program | | | | | 0.6 |
| 55 | EGD Greenhouse Gas Emissions Administration | | | | | 0.2 |
| 56 | EGD Reverse 2019 Gas Supply Plan Cost Consequences reversed | | | | | (3.9) |
| 57 | EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal | | | | | 3.9 |
| 58 | Union Average Use/ Normalized Average Consumption | | | | | 6.7 |
| 59 | Union Parkway Obligation Rate Variance | | | | | 0.0 |
| 60 | Union Incremental Capital Module | | | | | (5.6) |
| 61 | Union Capital Pass-through | | | | | (1.1) |
| 62 | Union LRAM | | | | | 1.4 |
| 63 | Union Federal Carbon Program | | | | | 1.2 |
| 64 | Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues | | | | | (17.7) |
| 66 | Miscellaneous | | | | | 0.7 |
| | Total Utility Revenue | | | | | 2,281.9 |

FOR THE YEAR ENDED DECEMBER 31, 2021

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 | Col. 9 | |
|----------|---|-----------|---------|--------------------|--|------------|------------|----------------------------|--------|---------|
| | Customer Meters | | | Throughput Volumes | | | Revenues | | | |
| Line No. | Sales | T-Service | Total | Sales | (10 ³ M ³) T-Service | Total | Sales | (\$ Millions) T-Service | Total | |
| 1 | General Service | | | | | | | | | |
| 2 | Rate 1 | 2,064,173 | 34,054 | 2,098,227 | 4,665,992 | 82,730 | 4,748,722 | 1,749.7 | 18.5 | 1,768.3 |
| 3 | Rate 6 | 147,546 | 22,416 | 169,962 | 2,740,101 | 1,698,331 | 4,438,432 | 775.8 | 144.3 | 920.1 |
| 4 | Rate 9 | 2 | 0 | 2 | 3 | 0 | 3 | 0.0 | 0.0 | 0.0 |
| 5 | Total EGD Rate Zone | 2,211,721 | 56,470 | 2,268,191 | 7,406,097 | 1,781,061 | 9,187,158 | 2,525.6 | 162.8 | 2,688.3 |
| 6 | Rate M1 | 1,140,908 | 29,855 | 1,170,763 | 2,728,007 | 169,080 | 2,897,087 | 853.1 | 18.3 | 871.4 |
| 7 | Rate M2 | 4,749 | 3,206 | 7,955 | 526,743 | 587,121 | 1,113,864 | 109.2 | 35.0 | 144.2 |
| 8 | Rate O1 | 351,562 | 10,059 | 361,621 | 871,182 | 58,759 | 929,941 | 364.2 | 12.8 | 377.1 |
| 9 | Rate 10 | 1,369 | 878 | 2,247 | 148,728 | 163,067 | 311,794 | 40.9 | 20.0 | 60.9 |
| 10 | Total Union Rate Zones | 1,498,588 | 43,998 | 1,542,586 | 4,274,660 | 978,026 | 5,252,686 | 1,367.4 | 86.1 | 1,453.5 |
| 11 | Total General Service | 3,710,309 | 100,468 | 3,810,777 | 11,680,756 | 2,759,087 | 14,439,844 | 3,893.0 | 248.9 | 4,141.9 |
| 12 | Wholesale - Utility | | | | | | | | | |
| 13 | Rate M9 | 1 | 3 | 4 | 15,903 | 74,193 | 90,096 | 3.0 | 1.0 | 4.0 |
| 14 | Rate M10 | 2 | 0 | 2 | 320 | 0 | 320 | 0.1 | 0.0 | 0.1 |
| 15 | Total Wholesale - Utility | 3 | 3 | 6 | 16,223 | 74,193 | 90,415 | 3.1 | 1.0 | 4.1 |
| 16 | Contract Sales | | | | | | | | | |
| 17 | Rate 100 | 6 | 10 | 16 | 12,899 | 21,095 | 33,994 | 2.9 | 1.8 | 4.7 |
| 18 | Rate 110 | 110 | 305 | 415 | 83,260 | 1,018,629 | 1,101,890 | 16.6 | 40.4 | 57.0 |
| 19 | Rate 115 | 2 | 15 | 17 | 1,002 | 386,695 | 387,697 | 0.2 | 8.2 | 8.3 |
| 20 | Rate 125 | 0 | 4 | 4 | 0 | 707,660 | 707,660 | 0.0 | 11.9 | 11.9 |
| 21 | Rate 135 | 7 | 35 | 42 | 2,624 | 60,488 | 63,112 | 0.6 | 1.6 | 2.2 |
| 22 | Rate 145 | 5 | 15 | 20 | 0 | 24,785 | 24,785 | 0.0 | 1.9 | 1.9 |
| 23 | Rate 170 | 1 | 22 | 23 | 6,302 | 249,399 | 255,701 | 1.1 | 1.2 | 2.3 |
| 24 | Rate 200 | 1 | 0 | 1 | 137,779 | 54,230 | 192,010 | 27.8 | 2.4 | 30.2 |
| 25 | Rate 300 | 0 | 2 | 2 | 0 | 269 | 269 | 0.0 | 0.1 | 0.1 |
| 26 | Rate 315 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0.0 | 0.0 |
| 27 | Total EGD Rate Zone | 132 | 408 | 540 | 243,868 | 2,523,251 | 2,767,118 | 49.2 | 69.4 | 118.6 |
| 28 | Rate M4 | 37 | 190 | 227 | 56,304 | 554,504 | 610,808 | 12.0 | 28.8 | 40.8 |
| 29 | Rate M7 | 5 | 56 | 61 | 31,987 | 654,366 | 686,353 | 6.7 | 21.2 | 27.9 |
| 30 | Rate 20 | 5 | 54 | 59 | 8,464 | 629,136 | 637,600 | 2.9 | 30.6 | 33.5 |
| 31 | Rate 100 | 0 | 12 | 12 | 0 | 958,587 | 958,587 | 0.0 | 11.5 | 11.5 |
| 32 | Rate T-1 | 0 | 39 | 39 | 0 | 453,007 | 453,007 | 0.0 | 13.9 | 13.9 |
| 33 | Rate T-2 | 0 | 25 | 25 | 0 | 4,700,474 | 4,700,474 | 0.0 | 76.0 | 76.0 |
| 34 | Rate T-3 | 0 | 1 | 1 | 0 | 241,187 | 241,187 | 0.0 | 7.2 | 7.2 |
| 35 | Rate M5 | 4 | 34 | 38 | 4,043 | 59,468 | 63,511 | 0.8 | 2.3 | 3.1 |
| 36 | Rate 25 | 37 | 30 | 67 | 79,188 | 64,709 | 143,898 | 15.6 | 3.1 | 18.8 |
| 37 | Rate 30 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0.0 | 0.0 |
| 38 | Total Union Rate Zones | 88 | 441 | 529 | 179,987 | 8,315,439 | 8,495,425 | 38.0 | 194.7 | 232.7 |
| 39 | Total Contract Sales | 220 | 849 | 1,069 | 423,854 | 10,838,690 | 11,262,544 | 87.2 | 264.1 | 351.3 |
| 40 | Subtotal | 3,710,532 | 101,320 | 3,811,852 | 12,120,833 | 13,671,970 | 25,792,803 | 3,983.3 | 514.0 | 4,497.3 |
| 41 | Accounting Adjustments: | | | | | | | | | |
| 42 | EGT Tax Variance | | | | | | | | | (18.0) |
| 43 | EGT Accounting Policy Change | | | | | | | | | (16.2) |
| 44 | EGD Average Use / Normalized Average Consumption | | | | | | | | | 15.4 |
| 45 | EGD Dawn Access COS (DACDA) | | | | | | | | | 2.0 |
| 46 | EGD Incremental Capital Module | | | | | | | | | 0.2 |
| 47 | EGD LRAM | | | | | | | | | 0.0 |
| 48 | EGD Federal Carbon Program | | | | | | | | | 0.7 |
| 49 | EGD Greenhouse Gas Emissions Administration | | | | | | | | | 0.1 |
| 50 | EGD Transactional Services Revenue | | | | | | | | | 12.0 |
| 51 | Union Average Use / Normalized Average Consumption | | | | | | | | | 19.0 |
| 52 | Union Incremental Capital Module | | | | | | | | | (14.0) |
| 53 | Union Capital Pass-through | | | | | | | | | (4.4) |
| 54 | Union LRAM | | | | | | | | | 0.7 |
| 55 | Union Federal Carbon Program | | | | | | | | | 1.5 |
| 56 | Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues | | | | | | | | | (17.2) |
| 57 | Miscellaneous | | | | | | | | | 1.4 |
| 58 | Total Utility Revenue | | | | | | | | | 4,480.0 |

FOR THE YEAR ENDED DECEMBER 31, 2021

4,640.1

FOR THE YEAR ENDED DECEMBER 31, 2020

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 | Col. 9 | |
|----------|---|-----------|---------|--------------------|----------------------|------------|------------|----------------------------|--------|---------|
| | Customer Meters | | | Throughput Volumes | | | Revenues | | | |
| Line No. | Sales | T-Service | Total | Sales | (10³M³) T-Service | Total | Sales | (\$ Millions) T-Service | Total | |
| 1 | General Service | | | | | | | | | |
| 2 | Rate 1 | 2,020,078 | 44,454 | 2,064,531 | 4,789,664 | 104,740 | 4,894,404 | 1,618.2 | 28.4 | 1,646.6 |
| 3 | Rate 6 | 145,283 | 23,801 | 169,084 | 2,810,280 | 1,840,046 | 4,650,326 | 663.4 | 187.5 | 850.9 |
| 4 | Rate 9 | 2 | 0 | 2 | 127 | 0 | 127 | 0.0 | 0.0 | 0.0 |
| 5 | Total EGD Rate Zone | 2,165,363 | 68,254 | 2,233,617 | 7,600,071 | 1,944,786 | 9,544,857 | 2,281.6 | 215.9 | 2,497.5 |
| 6 | Rate M1 | 1,128,040 | 35,176 | 1,163,216 | 2,815,940 | 187,938 | 3,003,878 | 772.5 | 19.9 | 792.4 |
| 7 | Rate M2 | 4,324 | 3,571 | 7,895 | 571,025 | 633,316 | 1,204,341 | 99.3 | 35.6 | 134.8 |
| 8 | Rate 01 | 347,480 | 12,515 | 359,995 | 913,225 | 69,511 | 982,736 | 340.3 | 14.5 | 354.8 |
| 9 | Rate 10 | 1,156 | 982 | 2,138 | 155,265 | 187,391 | 342,656 | 37.1 | 21.9 | 58.9 |
| 10 | Total Union Rate Zones | 1,481,000 | 52,244 | 1,533,244 | 4,455,454 | 1,078,157 | 5,533,611 | 1,249.1 | 91.9 | 1,341.0 |
| 11 | Total General Service | 3,646,363 | 120,498 | 3,766,861 | 12,055,525 | 3,022,943 | 15,078,468 | 3,530.7 | 307.8 | 3,838.5 |
| 12 | Wholesale - Utility | | | | | | | | | |
| 13 | Rate M9 | 1 | 3 | 4 | 16,236 | 72,529 | 88,765 | 2.5 | 0.9 | 3.5 |
| 14 | Rate M10 | 2 | 0 | 2 | 360 | 0 | 360 | 0.1 | 0.0 | 0.1 |
| 15 | Total Wholesale - Utility | 3 | 3 | 6 | 16,596 | 72,529 | 89,125 | 2.6 | 0.9 | 3.5 |
| 16 | Contract Sales | | | | | | | | | |
| 17 | Rate 100 | 2 | 7 | 9 | 9,142 | 10,969 | 20,111 | 1.8 | 1.2 | 3.0 |
| 18 | Rate 110 | 57 | 279 | 335 | 71,781 | 909,360 | 981,141 | 9.6 | 36.4 | 45.9 |
| 19 | Rate 115 | 1 | 19 | 20 | 728 | 377,311 | 378,039 | 0.2 | 7.6 | 7.8 |
| 20 | Rate 125 | 4 | 0 | 4 | 0 | 523,436 | 523,436 | 0.0 | 11.4 | 11.4 |
| 21 | Rate 135 | 5 | 36 | 40 | 1,785 | 63,502 | 65,287 | 0.4 | 1.6 | 2.0 |
| 22 | Rate 145 | 3 | 19 | 22 | 628 | 22,768 | 23,396 | 0.3 | 1.3 | 1.6 |
| 23 | Rate 170 | 3 | 18 | 21 | 4,843 | 242,587 | 247,430 | 0.6 | 0.7 | 1.4 |
| 24 | Rate 200 | 1 | 0 | 1 | 137,358 | 52,115 | 189,473 | 23.1 | 2.4 | 25.5 |
| 25 | Rate 300 | 2 | 0 | 2 | 0 | 262 | 262 | 0.0 | 0.1 | 0.1 |
| 26 | Rate 315 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0.0 | 0.0 |
| 27 | Total EGD Rate Zone | 77 | 377 | 454 | 226,265 | 2,202,309 | 2,428,574 | 36.0 | 62.6 | 98.7 |
| 28 | Rate M4 | 35 | 201 | 236 | 56,325 | 565,055 | 621,380 | 9.9 | 28.1 | 38.0 |
| 29 | Rate M7 | 4 | 49 | 53 | 28,488 | 589,884 | 618,372 | 4.7 | 17.1 | 21.8 |
| 30 | Rate 20 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 2.5 | 2.5 |
| 31 | Rate 20 Transportation | 4 | 53 | 57 | 9,423 | 769,053 | 778,476 | 3.1 | 27.5 | 30.6 |
| 32 | Rate 100 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0.0 | 0.0 |
| 33 | Rate 100 Transportation | 0 | 12 | 12 | 0 | 996,605 | 996,605 | 0.0 | 11.3 | 11.3 |
| 34 | Rate T-1 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 1.4 | 1.4 |
| 35 | Rate T-1 Transportation | 0 | 39 | 39 | 0 | 430,312 | 430,312 | 0.0 | 12.2 | 12.2 |
| 36 | Rate T-2 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 7.2 | 7.2 |
| 37 | Rate T-2 Transportation | 0 | 25 | 25 | 0 | 4,017,975 | 4,017,975 | 0.0 | 66.9 | 66.9 |
| 38 | Rate T-3 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 1.4 | 1.4 |
| 39 | Rate T-3 Transportation | 0 | 1 | 1 | 0 | 264,209 | 264,209 | 0.0 | 5.8 | 5.8 |
| 40 | Rate M5 | 5 | 33 | 38 | 2,712 | 59,105 | 61,817 | 0.4 | 2.1 | 2.6 |
| 41 | Rate 25 | 38 | 26 | 64 | 29,990 | 62,848 | 92,838 | 5.0 | 2.8 | 7.8 |
| 42 | Rate 30 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0.0 | 0.0 |
| 43 | Total Union Rate Zones | 86 | 439 | 525 | 126,938 | 7,755,045 | 7,881,983 | 23.1 | 186.2 | 209.4 |
| 44 | Total Contract Sales | 163 | 816 | 979 | 353,203 | 9,957,354 | 10,310,557 | 59.2 | 248.8 | 308.0 |
| 45 | Subtotal | 3,646,529 | 121,318 | 3,767,846 | 12,425,324 | 13,052,825 | 25,478,150 | 3,592.5 | 557.6 | 4,150.1 |
| 46 | Accounting Adjustments: | | | | | | | | | |
| 47 | EGI Tax Variance | | | | | | | | | (13.4) |
| 48 | EGI Accounting Policy Change | | | | | | | | | (14.0) |
| 49 | EGD Average Use/ Normalized Average Consumption | | | | | | | | | (4.6) |
| 50 | EGD Dawn Access Cost | | | | | | | | | 2.1 |
| 51 | EGD Incremental Capital Module | | | | | | | | | (0.3) |
| 52 | EGD Transactional Services Revenue | | | | | | | | | 12.0 |
| 53 | EGD LRAM | | | | | | | | | 0.0 |
| 54 | EGD Federal Carbon Program | | | | | | | | | 0.6 |
| 55 | EGD Greenhouse Gas Emissions Administration | | | | | | | | | 0.2 |
| 56 | EGD Reverse 2019 Gas Supply Plan Cost Consequences reversed | | | | | | | | | (3.9) |
| 57 | EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal | | | | | | | | | 3.9 |
| 58 | Union Average Use/ Normalized Average Consumption | | | | | | | | | 7.2 |
| 59 | Union Parkway Obligation Rate Variance | | | | | | | | | 0.0 |
| 60 | Union Incremental Capital Module | | | | | | | | | (5.6) |
| 61 | Union Capital Pass-through | | | | | | | | | (1.1) |
| 62 | Union LRAM | | | | | | | | | 1.4 |
| 63 | Union Federal Carbon Program | | | | | | | | | 1.2 |
| 64 | Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues | | | | | | | | | (17.7) |
| 66 | Miscellaneous | | | | | | | | | 0.7 |
| 67 | Total Utility Revenue | | | | | | | | | 4,118.8 |

FOR THE YEAR ENDED DECEMBER 31, 2020

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 | Col. 9 | |
|----------|---|-----------|---------|---|------------|------------|---------------------------|-----------|--------|---------|
| | Customer Meters | | | Throughput Volumes (10 ³ M ³) | | | Revenues (\$ Millions) | | | |
| Line No. | Sales | T-Service | Total | Sales | T-Service | Total | Sales | T-Service | Total | |
| 1 | General Service | | | | | | | | | |
| 2 | Rate 1 | 2,020,078 | 44,454 | 2,064,531 | 4,925,067 | 107,556 | 5,032,623 | 1,650.3 | 28.7 | 1,679.0 |
| 3 | Rate 6 | 145,283 | 23,801 | 169,084 | 2,919,935 | 1,887,608 | 4,807,543 | 686.1 | 190.5 | 876.6 |
| 4 | Rate 9 | 2 | 0 | 2 | 127 | 0 | 127 | 0.0 | 0.0 | 0.0 |
| 5 | Total EGD Rate Zone | 2,165,363 | 68,254 | 2,233,617 | 7,845,129 | 1,995,164 | 9,840,293 | 2,336.4 | 219.2 | 2,555.6 |
| 6 | Rate M1 | 1,128,040 | 35,176 | 1,163,216 | 2,966,369 | 197,978 | 3,164,348 | 801.4 | 20.3 | 821.7 |
| 7 | Rate M2 | 4,324 | 3,571 | 7,895 | 595,912 | 660,918 | 1,256,830 | 104.1 | 36.9 | 141.0 |
| 8 | Rate 01 | 347,480 | 12,515 | 359,995 | 954,899 | 72,683 | 1,027,582 | 352.7 | 15.0 | 367.6 |
| 9 | Rate 10 | 1,156 | 982 | 2,138 | 160,473 | 193,677 | 354,151 | 38.4 | 22.6 | 61.0 |
| 10 | Total Union Rate Zones | 1,481,000 | 52,244 | 1,533,244 | 4,677,654 | 1,125,257 | 5,802,911 | 1,296.5 | 94.8 | 1,391.3 |
| 11 | Total General Service | 3,646,363 | 120,498 | 3,766,861 | 12,522,783 | 3,120,421 | 15,643,204 | 3,632.9 | 314.0 | 3,946.9 |
| 12 | Wholesale - Utility | | | | | | | | | |
| 13 | Rate M9 | 1 | 3 | 4 | 16,236 | 72,529 | 88,765 | 2.5 | 0.9 | 3.5 |
| 14 | Rate M10 | 2 | 0 | 2 | 360 | 0 | 360 | 0.1 | 0.0 | 0.1 |
| 15 | Total Wholesale - Utility | 3 | 3 | 6 | 16,596 | 72,529 | 89,125 | 2.6 | 0.9 | 3.5 |
| 16 | Contract Sales | | | | | | | | | |
| 17 | Rate 100 | 2 | 7 | 9 | 9,142 | 10,969 | 20,111 | 1.8 | 1.2 | 3.0 |
| 18 | Rate 110 | 57 | 279 | 335 | 71,936 | 910,575 | 982,511 | 9.6 | 36.4 | 46.0 |
| 19 | Rate 115 | 1 | 19 | 20 | 730 | 377,426 | 378,156 | 0.2 | 7.6 | 7.8 |
| 20 | Rate 125 | 4 | 0 | 4 | 0 | 523,436 | 523,436 | 0.0 | 11.4 | 11.4 |
| 21 | Rate 135 | 5 | 36 | 40 | 1,785 | 63,502 | 65,287 | 0.4 | 1.6 | 2.0 |
| 22 | Rate 145 | 3 | 19 | 22 | 628 | 22,937 | 23,565 | 0.3 | 1.3 | 1.6 |
| 23 | Rate 170 | 3 | 18 | 21 | 4,847 | 243,184 | 248,031 | 0.6 | 0.7 | 1.4 |
| 24 | Rate 200 | 1 | 0 | 1 | 142,758 | 52,433 | 195,190 | 24.0 | 2.4 | 26.4 |
| 25 | Rate 300 | 2 | 0 | 2 | 0 | 262 | 262 | 0.0 | 0.1 | 0.1 |
| 26 | Rate 315 | | 0 | 0 | | 0 | 0 | | 0.0 | 0.0 |
| 27 | Total EGD Rate Zone | 77 | 377 | 454 | 231,825 | 2,204,724 | 2,436,549 | 36.9 | 62.7 | 99.6 |
| 28 | Rate M4 | 35 | 201 | 236 | 56,325 | 565,055 | 621,380 | 9.9 | 28.1 | 38.0 |
| 29 | Rate M7 | 4 | 49 | 53 | 28,488 | 589,884 | 618,372 | 4.7 | 17.1 | 21.8 |
| 30 | Rate 20 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 2.5 | 2.5 |
| 31 | Rate 20 Transportation | 4 | 53 | 57 | 9,423 | 769,053 | 778,476 | 3.1 | 27.5 | 30.6 |
| 32 | Rate 100 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0.0 | 0.0 |
| 33 | Rate 100 Transportation | 0 | 12 | 12 | 0 | 996,605 | 996,605 | 0.0 | 11.3 | 11.3 |
| 34 | Rate T-1 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 1.4 | 1.4 |
| 35 | Rate T-1 Transportation | 0 | 39 | 39 | 0 | 430,312 | 430,312 | 0.0 | 12.2 | 12.2 |
| 36 | Rate T-2 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 7.2 | 7.2 |
| 37 | Rate T-2 Transportation | 0 | 25 | 25 | 0 | 4,017,975 | 4,017,975 | 0.0 | 66.9 | 66.9 |
| 38 | Rate T-3 Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 1.4 | 1.4 |
| 39 | Rate T-3 Transportation | 0 | 1 | 1 | 0 | 264,209 | 264,209 | 0.0 | 5.8 | 5.8 |
| 40 | Rate M5 | 5 | 33 | 38 | 2,712 | 59,105 | 61,817 | 0.4 | 2.1 | 2.6 |
| 41 | Rate 25 | 38 | 26 | 64 | 29,990 | 62,848 | 92,838 | 5.0 | 2.8 | 7.8 |
| 42 | Rate 30 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0 | 0.0 | 0.0 |
| 43 | Total Union Rate Zones | 86 | 439 | 525 | 126,938 | 7,755,045 | 7,881,983 | 23.1 | 186.2 | 209.4 |
| 44 | Total Contract Sales | 163 | 816 | 979 | 358,763 | 9,959,769 | 10,318,532 | 60.1 | 248.9 | 309.0 |
| 45 | Subtotal | 3,646,529 | 121,318 | 3,767,846 | 12,898,142 | 13,152,718 | 26,050,861 | 3,695.6 | 563.8 | 4,259.4 |
| 46 | Accounting Adjustments: | | | | | | | | | |
| 47 | EGI Tax Variance | | | | | | | | | (13.4) |
| | EGI Elimination of 2018 Tax Variance | | | | | | | | | 0.0 |
| 48 | EGI Accounting Policy Change | | | | | | | | | (14.0) |
| 49 | EGD Average Use/ Normalized Average Consumption | | | | | | | | | (4.6) |
| 50 | EGD Dawn Access Cost | | | | | | | | | 2.1 |
| 51 | EGD Incremental Capital Module | | | | | | | | | (0.3) |
| | EGD Elimination of 2018 Earnings Sharing Adjustment | | | | | | | | | 0.0 |
| 52 | EGD Transactional Services Revenue | | | | | | | | | 12.0 |
| 53 | EGD LRAM | | | | | | | | | 0.0 |
| 54 | EGD Federal Carbon Program | | | | | | | | | 0.6 |
| 55 | EGD Greenhouse Gas Emissions Administration | | | | | | | | | 0.2 |
| 56 | EGD Reverse 2019 Gas Supply Plan Cost Consequences | | | | | | | | | (3.9) |
| 57 | EGD Elimination of 2019 Gas Supply Plan Cost Consequences reversal | | | | | | | | | 3.9 |
| 58 | Union Average Use/ Normalized Average Consumption | | | | | | | | | 7.2 |
| 59 | Union Parkway Obligation Rate Variance | | | | | | | | | 0.0 |
| 60 | Union Incremental Capital Module | | | | | | | | | (5.6) |
| 61 | Union Capital Pass-through | | | | | | | | | (1.1) |
| 62 | Union LRAM | | | | | | | | | 1.4 |
| 63 | Union Federal Carbon Program | | | | | | | | | 1.2 |
| 64 | Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues | | | | | | | | | (17.7) |
| 66 | Miscellaneous | | | | | | | | | 0.7 |
| 67 | Total Utility Revenue | | | | | | | | | 4,224.3 |

EGI REVENUE FROM REGULATED STORAGE
& TRANSPORTATION OF GAS
2021 ACTUAL

| Line No. | Particulars (\$000s) | 2020 Actual | 2021 Actual |
|---|---|----------------|----------------|
| Revenue from Regulated Storage Services: | | | |
| 1 | C1 Off-Peak Storage | 1,002 | 433 |
| 2 | Supplemental Balancing Services | 1,016 | 640 |
| 3 | Gas Loans | 1 | 1 |
| 4 | C1 Short Term Firm Peak Storage | 2,715 | 1,536 |
| 5 | Short Term Storage and Balancing Services Deferral | 907 | 3,577 |
| 6 | Rate 325: Transmission, Compression, & Storage | 1,988 | 2,169 |
| 7 | Less: Elimination of charges between EGD and Union rate zones | (2,000) | (2,226) |
| 8 | Total Regulated Storage Revenue Net of Deferral | \$ 5,630 | \$ 6,130 |
| Revenue from Regulated Transportation Services: | | | |
| 9 | M12 Transportation | 206,677 | 206,637 |
| 10 | M12-X Transportation | 21,335 | 21,527 |
| 11 | C1 Long Term Transportation | 20,882 | 19,934 |
| 12 | Rate 332: Gas Transmission | 17,804 | 18,107 |
| 13 | C1 Short Term Transportation | 5,698 | 7,226 |
| 14 | Gross Exchange Revenue | 999 | 1,729 |
| 15 | Rate 331: Gas Transmission | 259 | 165 |
| 16 | M13 Local Production | 122 | 157 |
| 17 | M16 Transportation | 1,089 | 926 |
| 18 | M17 transportation | 109 | 545 |
| 19 | S&T:Transportation Carbon Facility Collection | 1,931 | 2,692 |
| 20 | Other S&T Revenue | 1,580 | 1,440 |
| 21 | Less: Elimination of charges between EGD and Union rate zones | (136,155) | (138,489) |
| 22 | Total Regulated Transportation Revenue Net of Deferral | \$ 142,330 | \$ 142,597 |

EGI UTILITY OTHER REVENUE AND OTHER INCOME
2021 ACTUALS

| Line No. | Particulars | Col. 1 2020 Utility Revenue (\$Millions) | Col. 2 2021 Utility Revenue (\$Millions) |
|-------------|---|--|--|
| 1. | Late Payment Penalties | 20.8 | 19.9 |
| 2. | Account Opening Charges | 9.8 | 11.1 |
| 3. | Other Billing Revenue | 3.0 | 3.2 |
| 4. | Customer Billing Revenue | 33.6 | 34.1 |
| 5. | Open Bill Revenue | 5.4 | 5.4 |
| | Distributor Consolidated Billing and Direct | | |
| 6. | Purchase Administration Charges | 2.4 | 2.3 |
| 7. | Mid Market Transactions | 1.1 | 1.2 |
| 8. | CNG Rental Revenue | 1.8 | 1.8 |
| 9. | Other Operating Revenue | 3.4 | 4.2 |
| 10. | Total Other Revenue | 47.7 | 49.1 |
| 11. | Other Income | 4.5 | 0.9 |
| 12. | Total Other Revenue and Other Income | 52.2 | 50.0 |

UTILITY O&M

1. This evidence explains the drivers in the Utility Operating and Maintenance (O&M) expense change from 2021 to 2020.
2. The Utility O&M schedule for 2021 preserves the presentation from the 2020 ESM Proceeding (EB-2021-0149) to provide transparency to all expense categories and in particular, segregating Corporate Shared Services (CSS), Demand Side Management (DSM), and Integration-related costs. The Company recognizes that this O&M presentation is useful to inform stakeholders about operating costs, and as such, has maintained the presentation to allow the driver explanations to be comparable between years.
3. Table 1 presents 2021 O&M expenses relative to the prior year. As in 2020, Enbridge Gas provided an appendix reconciling O&M results presented in the format of Table 1 compared to formats previous to 2019. Please refer to Appendix A for the reconciliation for 2021 results and presentation. Given the fact that Enbridge Gas now has three years of historical information presented in the format in Table 1, it is proposed that the reconciliation in Appendix A is no longer required or useful for the remaining deferred rebasing years of 2022 and 2023. Enbridge Gas requests approval to not provide the Appendix A reconciliation going forward after this proceeding.
4. Overall, O&M expenses decreased by \$32.3 million primarily due to the non-recurrence of the one-time severance costs for voluntary workforce departures that occurred in 2020. Sustained synergy savings also contributed to the decrease. These decreases were partially offset by increases primarily in CSS, compensation and benefits, outside services, donations and memberships, and vehicle related repairs and maintenance.

Table 1

UTILITY O&M
2021 & 2020 ACTUALS

| Line No. | Col. 1 Expense Categories | Col. 2 2020 Actual (\$M) | Col. 3 2021 Actual (\$M) | Col. 4 \$ change | Col. 5 % change |
|----------|---|-----------------------------------|-----------------------------------|---------------------|--------------------|
| 1 | Compensation and Benefits | 354.7 | 369.8 | 15.1 | 4.3% |
| 2 | Employee Related Services and Development | 1.5 | 1.5 | (0.0) | -2.0% |
| 3 | Materials and Supplies | 29.9 | 32.5 | 2.6 | 8.6% |
| 4 | Outside Services | 220.8 | 232.1 | 11.3 | 5.1% |
| 5 | Transportation Related Repairs and Maintenance | 6.9 | 5.7 | (1.2) | -17.8% |
| 6 | Vehicle Related Repairs and Maintenance | 14.3 | 19.8 | 5.5 | 38.1% |
| 7 | Rents and Leases | 9.9 | 11.1 | 1.2 | 11.7% |
| 8 | Telecommunications | 0.3 | 0.2 | (0.1) | -35.1% |
| 9 | Travel and Entertainment | 3.1 | 3.7 | 0.6 | 20.1% |
| 10 | Donations and Memberships | 3.2 | 11.3 | 8.1 | 258.1% |
| 11 | Admin Expenses | (1.6) | (4.1) | (2.5) | 162.1% |
| 12 | Allocations & Recoveries | (17.8) | (16.5) | 1.3 | -7.1% |
| 13 | Corporate Shared Services (CSS) | 187.8 | 218.1 | 30.3 | 16.1% |
| 14 | DSM | 132.3 | 132.1 | (0.2) | -0.1% |
| 15 | Integration-Related Costs | 125.2 | 49.8 | (75.4) | -60.2% |
| 16 | Miscellaneous Expense | 14.7 | 9.8 | (4.9) | -33.4% |
| 17 | Capitalization on Non-CSS | (119.5) | (138.2) | (18.7) | 15.7% |
| 18 | O&M Subtotal before Eliminations | 965.7 | 938.7 | (27.0) | -2.8% |
| 19 | Donations | (0.6) | (3.6) | (3.0) | 465.1% |
| 20 | CDM Program | 0.1 | 0.0 | (0.1) | -100.0% |
| 21 | ABC T-service Program | (0.2) | (0.3) | (0.1) | 76.3% |
| 22 | Other Eliminations | 0.0 | (0.1) | (0.1) | |
| 23 | Unregulated Adjustments | (16.6) | (18.5) | (1.9) | 11.5% |
| 24 | Total Unregulated/Non-Utility Eliminations | (17.3) | (22.5) | (5.2) | 30.4% |
| 25 | Total Net Utility O&M Expense | 948.5 | 916.2 | (32.3) | -3.4% |

5. With the exclusion of \$77.7 million of severance costs in 2020, the remaining integration-related costs (Line 15) increased by \$2.4 million as integration initiatives continue to be pursued across all functional areas.
6. CSS costs (Line 13) include business functions such as Legal, Finance, Human Resources and Technology Information Services (TIS) that serve business units across the Enbridge enterprise. CSS costs are primarily comprised of compensation

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7. and benefits for CSS employees. Costs are charged to the individual business units based on appropriate cost allocation in relation to the services received.
8. CSS costs were \$30.3 million higher than the prior year primarily due to: higher pension and benefits; higher information technology costs driven by cybersecurity investments resulting from government mandates in response to heightened threats to energy companies, deployment and sustainment costs of new technology to support business requirements; higher insurance costs from market conditions brought about by heightened pandemic risk; and lower overhead capitalization of CSS costs (please see Table 2 for more detail).
9. Compensation and benefits (Line 1) increased \$15.1M from higher pension and benefits costs. The pension increase was the result of a higher actuarial valuation. Short-term incentive payments (STIP) were higher from stronger performance compared to 2020. Stock-based compensation (SBC) was similarly higher as a result of a higher share price.
10. Outside services (Line 4) increased \$11.3M over the prior year primarily due to an increase in integrity spending, higher locates costs due to higher contract rates, higher postage costs from lower e-bill utilization, higher contract costs for call center, back-office billing and collections support, and increases in regulatory consulting costs related to rebasing preparations as well as higher regulatory fees reflecting the volume of proceedings including Integrated Resource Planning (IRP).
11. Donations and memberships (Lines 10 and 19) increased \$5.1M (after elimination of donations not deducted for utility purposes) over the prior year due to higher sponsorships relative to 2020 when the pandemic curtailed sponsorship opportunities. Also contributing to the unfavorable variance is the transfer of Union

Gas Low-Income Energy Assistance Program (LEAP) amounts to the Donations and Memberships category in 2021 for tracking and reporting alignment with Enbridge Gas Distribution (EGD) LEAP disbursements. The increase is offset in the Admin Expenses category (Line 11).

12. Vehicle-related repair expenses (Line 6) increased \$5.5M in 2021 due to the higher maintenance and repairs needs of an aging fleet of vehicles, as well as from higher fuel prices.

1. 2021 Overhead Capitalization

13. The following section describes total overhead capitalization for both CSS (included in Line 13) and non-CSS cost categories (Line 17).

14. Overhead capitalization applies to all expense categories except integration-related costs, which are fully expensed. Total combined overhead capitalization was \$10.4M more than the prior year (Table 2).

15. Non-CSS overhead capitalization increased by \$18.7M driven by the increases in O&M expenses noted in the previous section.

16. CSS overhead capitalization decreased by \$8.3M from the prior year primarily due to lower direct labour engaged in 2021 capital activity. With the completion of the labor-intensive Customer Information System (CIS) capital Information Technology (IT) project in 2020, direct labour burdens were lower in 2021 by comparison. While CSS costs increased, the increase was primarily due to higher pension and benefits, which flow to capital through burdening of direct and indirect labour.

Table 2

Total Overhead Capitalization Impact on O&M

| | 2020 Actual (\$M) | 2021 Actual (\$M) | Variance (\$M) |
|----------------------------|-------------------------|-------------------------|-------------------|
| CSS-related Capitalization | (105.0) | (96.7) | 8.3 |
| Capitalization on Non-CSS | (119.5) | (138.2) | (18.7) |
| | (224.5) | (234.9) | (10.4) |

17. While reconciliation tables were provided in the 2020 ESM application (Appendices, EB-2021-0149) to aid in the understanding and adoption of the new schedule, as well as to provide visibility to Corporate Allocations and Recoveries as agreed to in the 2019 ESM Settlement Proposal, inbound allocations and outbound recoveries are no longer relevant for 2021 as all CSS costs are inbound to Enbridge Gas. Affiliates are similarly allocated their charges directly through Enbridge Inc. and not through Enbridge Gas. Table 3 summarizes the Total Corporate allocation, the CSS capitalization applied, and Total Net CSS. Variance explanations are as noted in previous sections.

Table 3

Corporate Allocations and CSS

| | <u>2020</u> | <u>2021</u> | <u>2020-2021</u> <u>Variance</u> |
|-----------------------------|-------------|-------------|-------------------------------------|
| Total Gross CSS | 292.8 | 314.8 | 22.0 |
| Less: Capitalization of CSS | (105.0) | (96.7) | 8.3 |
| Net CSS | 187.8 | 218.1 | 30.3 |

Appendix A

RECONCILIATION OF UTILITY O&M SCHEDULE
2020 & 2021 Results

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 | Col. 9 | Col. 10 | Col. 11 |
|------|--|-----------------------|-----------|-------------|-------------|----------|-----------|-------------|---------|-----------|-----------|
| | 2020 ACTUAL | | | | 2021 ACTUAL | | | | | 2020-2021 | 2020-2021 |
| Line | | 2020 | Central | DSM & | 2020 | 2021 | Central | DSM & | 2021 | | |
| No. | Expense Categories (\$M) | As filed ¹ | Functions | Integration | Revised | Previous | Functions | Integration | Revised | \$ change | % change |
| | | | Costs | Costs | | Format | Costs | Costs | | | |
| 1 | Compensation and Benefits | 572.2 | (108.0) | (109.5) | 354.7 | 514.2 | (112.8) | (31.6) | 369.8 | 15.2 | 4.3% |
| 2 | Employee Related Services and Development | 6.5 | (4.8) | (0.2) | 1.5 | 5.1 | (3.1) | (0.5) | 1.5 | (0.0) | -2.0% |
| 3 | Materials and Supplies | 92.1 | (5.3) | (56.9) | 29.9 | 97.7 | (7.9) | (57.3) | 32.5 | 2.6 | 8.6% |
| 4 | Outside Services | 341.3 | (36.6) | (83.9) | 220.8 | 364.0 | (39.3) | (92.6) | 232.1 | 11.3 | 5.1% |
| 5 | Transportation Related Repairs and Maintenance | 9.8 | (2.9) | (0.0) | 6.9 | 9.2 | (3.5) | (0.0) | 5.7 | (1.2) | -17.8% |
| 6 | Vehicle Related Repairs and Maintenance | 14.4 | (0.0) | (0.0) | 14.3 | 19.9 | (0.0) | (0.1) | 19.8 | 5.5 | 38.1% |
| 7 | Rents and Leases | 12.4 | (2.5) | (0.0) | 9.9 | 12.5 | (1.4) | - | 11.1 | 1.2 | 11.7% |
| 8 | Telecommunications | 3.8 | (3.5) | (0.0) | 0.3 | 2.5 | (2.3) | | 0.2 | (0.1) | -35.1% |
| 9 | Travel and Entertainment | 4.3 | (0.9) | (0.4) | 3.1 | 4.1 | (0.3) | (0.1) | 3.7 | 0.6 | 20.1% |
| 10 | Donations and Memberships | 4.3 | (0.2) | (0.9) | 3.2 | 12.4 | (0.3) | (0.7) | 11.3 | 8.1 | 258.1% |
| 11 | Admin Expenses | 0.9 | 0.8 | (3.3) | (1.6) | (4.7) | (1.2) | 1.7 | (4.1) | (2.5) | 162.1% |
| 12 | Allocations & Recoveries | 113.4 | (128.8) | (2.3) | (17.8) | 126.2 | (142.1) | (0.7) | (16.5) | 1.3 | -7.1% |
| 13 | Corporate Shared Services (CSS) | | 187.8 | | 187.8 | - | 218.1 | | 218.1 | 30.3 | 16.1% |
| 14 | DSM | | | 132.3 | 132.3 | - | | 132.1 | 132.1 | (0.2) | -0.1% |
| 15 | Integration-Related Costs | | | 125.2 | 125.2 | - | | 49.8 | 49.8 | (75.4) | -60.2% |
| 16 | Miscellaneous O&M Expense | 14.7 | | | 14.7 | 9.8 | | | 9.8 | (4.9) | -33.4% |
| 17 | Capitalization on non-CSS | (224.3) | 104.9 | | (119.5) | (234.3) | 96.0 | | (138.2) | (18.7) | 15.7% |
| 18 | O&M Subtotal before Eliminations | 965.7 | (0.0) | (0.0) | 965.7 | 938.7 | (0.0) | 0.0 | 938.7 | (27.0) | -2.8% |
| 19 | Donations | (0.6) | | | (0.6) | (3.6) | | | (3.6) | (3.0) | 465.1% |
| 20 | CDM Program | 0.1 | | | 0.1 | 0.0 | | | 0.0 | (0.1) | -100.0% |
| 21 | ABC T-service Program | (0.2) | | | (0.2) | (0.3) | | | (0.3) | (0.1) | 76.3% |
| 22 | Other Eliminations | 0.0 | | | 0.0 | (0.1) | | | (0.1) | (0.1) | - |
| 23 | Unregulated Adjustments | (16.6) | | | (16.6) | (18.5) | | | (18.5) | (1.9) | 11.5% |
| 24 | Total Unregulated/Non-Utility Eliminations | (17.3) | | | (17.3) | (22.5) | | | (22.5) | (5.2) | 30.4% |
| 25 | Total Net Utility O&M Expense | 948.5 | | | 948.5 | 916.2 | | | 916.2 | (32.3) | -3.4% |

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UTILITY CAPITAL EXPENDITURES

1. The purpose of this evidence is to provide information on Enbridge Gas' 2021 utility capital expenditures within the EGD and Union rate zones.

Table 1
Summary of Capital Expenditures 2021 Actual
(\$millions)

| | Col 1 | Col 2 | Col 3 |
|---------------------------|--------------|--------------|------------------|
| | EGD | UG | TOTAL EGI |
| Distribution Plant | 457.9 | 465.4 | 923.2 |
| Transmission Plant | - | 128.6 | 128.6 |
| General & Other Plant | 113.0 | 74.3 | 187.3 |
| Underground Storage Plant | 59.5 | 12.2 | 71.7 |
| | 630.4 | 680.4 | 1,310.8 |

2. The dollars presented are annual capital expenditures and are comparable to the presentation in the Asset Management Plan. Capital expenditures in ICM applications are presented on an in-service basis.
3. Table 2 below shows the regulated expenditures by Asset Class for each of the legacy rate zones. Further commentary regarding the year over year changes in capital expenditures are described by Asset Class in the narrative following Table 2.

Table 2
EGD Rate Zone by Asset Class
(\$millions)

| | Asset Class | 2020 | 2021 | Variance |
|-----------------------------------|--|--------------|--------------|-----------------|
| A | Compression Stations | 9.2 | 26.8 | 17.6 |
| B | Customer Connections | 117.5 | 172.0 | 54.4 |
| C | Distribution Pipe | 58.5 | 151.0 | 92.6 |
| D | Distribution Stations | 33.7 | 43.4 | 9.8 |
| E | Fleet & Equipment | 11.3 | 15.3 | 4.0 |
| F | Growth - Distribution System Reinforcement | 8.4 | 13.4 | 5.0 |
| G | Real Estate & Workplace Services | 22.2 | 40.2 | 18.0 |
| H | Technology Information Services (TIS) | 13.8 | 12.7 | (1.1) |
| I | Transmission Pipe and Underground Storage | 12.7 | 32.7 | 20.0 |
| J | Utilization | 31.3 | 34.8 | 3.5 |
| K | EA Fixed Overhead | 15.7 | 19.5 | 3.8 |
| L | Capitalized Overheads | 131.9 | - | (131.9) |
| M | Integration Capital | 19.2 | 44.8 | 25.6 |
| N | Community Expansion | 20.2 | 13.5 | (6.7) |
| O | Other | 1.6 | 10.1 | 8.6 |
| Total Capital Expenditures | | 507.2 | 630.4 | 123.2 |

Table 2
UG Rate Zone by Asset Class
(\$millions)

| | Asset Class | 2020 | 2021 | Variance |
|-----------------------------------|--|--------------|--------------|-----------------|
| A | Compression Stations | 17.3 | 15.5 | (1.8) |
| B | Customer Connections | 61.1 | 88.7 | 27.6 |
| C | Distribution Pipe | 134.3 | 296.1 | 161.8 |
| D | Distribution Stations | 27.7 | 47.8 | 20.1 |
| E | Fleet & Equipment | 8.9 | 11.4 | 2.5 |
| F | Growth - Distribution System Reinforcement | 61.6 | 35.1 | (26.5) |
| G | Real Estate & Workplace Services | 16.1 | 30.3 | 14.2 |
| H | Technology Information Services (TIS) | 9.0 | 10.1 | 1.2 |
| I | Transmission Pipe and Underground Storage | 20.8 | 46.8 | 26.0 |
| J | Utilization | 31.6 | 45.9 | 14.3 |
| K | EA Fixed Overhead | 3.8 | 5.9 | 2.2 |
| L | Capitalized Overheads | 90.3 | - | (90.3) |
| M | Integration Capital | 19.3 | 42.7 | 23.4 |
| N | Community Expansion | 0.7 | 3.8 | 3.1 |
| O | Other | (2.5) | 0.3 | 2.8 |
| Total Capital Expenditures | | 500.0 | 680.4 | 180.4 |

1. Descriptions of Asset Classes and Year over Year Variances

4. Effective January 2021, EGI is allocating capitalized overheads to projects based on the total pool of overheads and the total direct capital spend by rate zone. As a result, capitalized overheads are being reflected within the asset classes and will no longer shown as a separate asset class. This is consistent with the presentation of overheads in the Asset Management Plan and ICM applications (as of 2021).

A. Compression Stations

EGI (Union rate zone) uses compressors to move natural gas throughout the natural gas transmission system by compressing natural gas into transmission pipelines designed for high pressure and flow. Compressors are also used for both rate zones to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow.

Dehydration facilities are also included in the compression asset category. Dehydration facilities remove moisture from natural gas to ensure that the natural gas entering the transmission system meets the contractual standard of moisture content, and to avoid operational problems related to high moisture content. EGI operates one liquified natural gas (LNG) facility, the LNG facility serves to provide reserve capacity and balance operational loads during peak periods.

The EGD rate zone increased due to the pacing of large growth projects in 2021 including: Ph 1 (\$14.0M) and Ph 2 (\$2.2M) of the Corunna (SCOR) Meter Area Upgrade.

The Union rate zone had an overall decrease due to the timing of land purchases adjacent to facilities and the variability in the cost/timing of unplanned compressor failures that require capital treatment, countered by an increase in improvement projects.

The inclusion of overheads is a \$7.9M increase compared to 2020 spend.

B. Customer Connections

This asset class includes:

- The addition of new customers based on new housing or business starts;
- Customers converting to natural gas from another fuel source;
- Equipment and service upgrades to accommodate load growth of existing customers; and
- General customer growth costs include materials and installation of mains and services to attach new customers as well as the costs associated with the meter and regulator installation at the customers site.

In the EGD rate zone there was an increase in customers connected in 2021 compared to 2020. In both rate zones, the cost of labour and materials also increased due to shortages, inflation rates and unfavourable currency exchange rates.

The inclusion of overheads is a \$49.0M increase compared to 2020 spend.

C. Distribution Pipe

This asset class includes the maintenance, replacement, and renewal of pipelines and piping components (such as valves and fittings) used to transport natural gas within the distribution system or to end-use customers. It includes steel and plastic pipe, as well as services to customers.

In the EGD rate, the increase was largely driven by the timing of vintage steel investments, the significant investment for NPS 20 Lake Shore Replacement (Cherry to Bathurst) (\$20.9M), the return of the AMP fitting and other programs following curtailment in 2020 for COVID-19.

For the Union rate zone, the increase was driven by large ICM projects including the London Lines Replacement (\$73.4M) and the West Portion of the Windsor Lines (\$34.2M).

Both rate zones saw increases in integrity retrofits and digs and relocations compared to 2020. Both rate zones saw cost variances driven by the deferral of work as a result of inflation and COVID-19 impacts to materials, accessibility and resources.

The inclusion of overheads is a \$83.2M increase compared to 2020 spend.

D. Distribution Stations

These assets are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.

The EGD rate zone variance is due to minor shifts in investment cost and timing.

In the Union rate zone, the overall increase was driven by an increase in the Station Rebuilds & B and C Stations program and increased Integrity Assessments to establish the condition of the station components and adjust project scopes to address the integrity findings. This was partially offset by a decrease in both CNG stations and Gate, Feeder and A Stations due to Dawn CNG (\$1.4M), Hamilton Gate 1 Rebuild (\$9.3M) and Oxford Gate Station (\$7.0M) requiring capital spend in 2020.

The inclusion of overheads is a \$17.1M increase compared to 2020 spend.

E. Fleet & Equipment

The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by EGI to support its business needs.

For the EGD rate zone, spend was pulled forward into 2021 for the TDW ProStopp tool (\$4.1M) which improves safety for workers during construction activities. This was countered by a decrease in vehicle purchases due to delays in supply chain.

The Union Gas rate zones did not have significant variances from 2020.

The inclusion of overheads is a \$5.0M increase compared to 2020 spend.

F. Growth – Distribution System Reinforcement

The Growth asset class includes reinforcements driven by customer and load growth.

For the EGD rate zone, there was an overall increase due to investment cost and timing.

For the Union rate zones, there was an overall decrease due to the larger Growth projects executed in 2020, including Kingsville Transmission (\$9.8M) and Owen Sound Reinforcement Ph 4 (\$56.4M). In 2021, the significant Growth projects were Byron Transmission Station (\$14.0M) and Staples Reinforcement (\$5.7M).

The inclusion of overheads is a \$9.0M increase compared to 2020 spend.

G. Real Estate and Workplace Services

The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings.

There is a base spend for each rate zone that supports building repairs and acquisition of furnishings. Variances are driven by the specific land purchases and building renovations that occur in a given year. Land acquisitions are driven by market availability and are aligned with the long-term strategies described in the Asset Management Plan.

In 2021, there was a significant investment in lands to execute the SMOC/Coventry Facility Consolidation (\$15.7M) and the Kennedy Road Expansion Project (\$2.6M) in the EGD rate zone. For the Union rate zone, the significant investment was the new Belleville Property Construction (\$7.5M). The significant real estate investments vary year over year due to market availability and project scope variation to meet business facility requirements.

Significant renovations at for the VPC Annex/Metershop Area Renovations (\$9.1M) in the EGD rate zone and the 50 Keil Drive Renovations (\$6.1M 2nd Floor & \$5.1M 3rd Floor) in the Union rate zone occurred in 2021.

The inclusion of overheads is a \$13.2M increase compared to 2020 spend.

H. Technology Information Services

The Technology Information Services (TIS) asset class includes:

- General Hardware (Laptops/Desktops and Desktop sustainment equipment, networks, servers and security);
- Specialized Hardware (to support specific business needs such as meter

reading equipment, call center network devices);

- Software assets consisting of packaged applications, developed applications, and application infrastructure software; and
- Communications assets including mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).

For the EGD rate zone, there was a decrease in the TIS infrastructure compared to 2020 due to higher spends on Desktop Replacement (\$2.9M) and the Microsoft Enterprise Agreement (\$1.8M) in 2020.

For the UG rate zone, there was no significant variance.

The inclusion of overheads is a \$4.3M increase compared to 2020 spend.

I. Transmission Pipe and Underground Storage

This asset class includes the pipelines that form the backbone of the gas transmission system as well as the underground storage reservoirs in St. Clair Township near Sarnia, Crowland Township in Welland, and in Chatham-Kent.

Increases in the EGD rate zone were primarily related to the timing of land purchases at facilities, an increase in MOP verification and remediation replacement projects, the timing of the Wilksport (LWLK) Well Debris Filter improvement project (\$2.5M) and an increase in retrofits & integrity digs for the Integrity Management Program.

In the UG rate zone, the Sarnia Expansion Growth Projects (\$10.8M Novacor Station & 21.1M NPS 20 Dow to Bluewater [LTC: EB-2019-0218]) were the

major driver to the increase. The 2021 replacement spend was lower than 2020, where the execution of the 2020 Trafalgar projects (\$12.8M) took place.

The inclusion of overheads is a \$14.8M increase compared to 2020 spend.

J. Utilization

The utilization asset class includes measurement & regulation systems at customer premises, below ground and internal piping systems after the meter, and customer-owned systems¹.

The EGD rate zone saw reductions in planned meter exchanges as a result of COVID-19 and its impact on supply chain and contractor resources.

Meter purchases in Union rate zone were higher in 2021 compared to 2020 as meters from 2020 were advanced and executed in 2019.

The inclusion of overheads is a \$15.1M increase compared to 2020 spend.

K. EA Fixed Overheads

The EA fixed overhead asset class includes cost for Alliance partner overheads and district contractor pre-work costs. The increase is due to additional planning work related to the Vintage Steel Program in the EGD rate zone and timing of payments for both EGD and Union rate zones.

¹ For customer owned systems that are downstream of the meter, the asset class is accountable for inspection at the time of initial installation and after re-introduction of gas. Maintenance and remediation of these assets are the responsibility of the customer.

L. Capitalized Overheads

As set out above, effective January 2021, EGI is allocating capitalized overheads to projects based on the total pool of overheads and the total direct capital spend by rate zone. As a result, capitalized overheads are being reflected within the asset classes and will no longer shown as a separate asset class. This is consistent with the presentation of overheads in the Asset Management Plan and ICM applications (as of 2021).

Total combined overhead capitalization increased by \$10M. The overhead increases are explained in B-3-1.

M. Integration Capital

Integration capital includes expenditures required to integrate the two legacy companies. EGI continues to evaluate projects to determine if they meet the criteria of integration capital: a one time incremental cost related to the amalgamation of the legacy utilities. Projects can be newly identified to address integration needs, or they may be driven by a need to replace an asset due to obsolescence. In either case, the project is classified as integration as it is driving a harmonized solution that adds value to the integrated utility. It is important to note that the work being addressed through some integration projects would have been required for either or both rate zones in the absence of amalgamation (because of factors such as obsolescence or growth), but the projects are nonetheless included as integration capital because the project is done for the amalgamated utility. An example of work related to integration expenditures would be the integration of the customer billing systems. These expenditures are excluded when calculating the thresholds for ICM capital.

The increase in the EGD rate zone is due to the purchase of land for the new GTA West site and the Integrated Utility Asset & Work Management project.

The increase in the UG rate zone is due to the completion of the CIS Integration project and continued work on the Cost of Gas project.

The inclusion of overheads is a \$16.4M increase compared to 2020 spend.

N. Community Expansion

Community expansion provides natural gas services to communities not currently using natural gas. In response to the Ontario Energy Board's (OEB) initiative to address the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas, EGI has filed proposals with the OEB designed to facilitate enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in Ontario.

In the EGD rate zone, the decrease in spend is primarily related to lower spend on the Fenelon Falls and Scugog Island projects due to construction completion, offset by the start of design work for the Community Expansion Phase 2 projects.

In the Union rate zone, the increase in spend is related to construction with the Northshore & Peninsula project.

5. Table 3 below shows the Asset Classes with storage spend for each rate zone and the allocation of costs between the regulated and unregulated segments of EGI's storage operations. Both the EGD and Union rate zones have OEB approved policies and methodologies for unregulated storage allocations. Allocations are

maintained at the individual asset level and updated annually to reflect additions and retirements to the assets. The allocations are applied to storage based capital projects in order to separate the regulated and unregulated costs. Regulated projects include indirect overhead allocations.

Table 3
EGD Rate Zone Storage by Asset Class 2021 Actual
(\$millions)

| | Asset Class | Regulated | Unregulated |
|-----------------------------------|---|------------------|--------------------|
| A | Compression Stations | 26.8 | 1.3 |
| B | Transmission Pipe and Underground Storage | 32.7 | 13.0 |
| Total Capital Expenditures | | 59.5 | 14.3 |

6. Compression Stations – significant regulated projects Corunna (SCOR) Meter Area Upgrade Phase 1 (\$14.0M), Corunna (SCOR) Meter Area Upgrade Phase 2 (\$2.2M), SCOR:100MODHdr Valves-Replace (\$1.4M) and SCOR:60004 iBalance-Upgrade (\$1.3M).
7. Transmission Pipe and Underground Storage – significant projects related to EGD’s regulated assets include Wilkesport MOP Remediation (\$6.2M), NPS16 LAD-WLK Interconnect MOP (\$4.1M), LLAD:, strategic land purchases at 2 locations around the underground storage facilities (\$5M), Wilksport (LWLK) Well Debris Filter (\$2.5M), NPS 16 Coveny Trans. Retrofit (\$2.3M) and NPS 16 COV Gathering Retrofit (\$2.2M). Significant unregulated projects include Pipeline and Meter Station – Upgrade (\$6.2M). This is part of the 2020/2021 Storage Enhancement project (EB-2020-0074) which will increase the maximum operating pressure of the Black Creek, Coveny and Wilkesport pools. The Storage Enhancement projects are being executed in 2 phases in order to meet the growing market demand for incremental storage space.

Table 3
UG Rate Zone Storage by Asset Class
(\$millions)

| | Asset Class | Regulated | Unregulated |
|-----------------------------------|---|------------------|--------------------|
| A | Compression Stations | 15.5 | 1.8 |
| B | Transmission Pipe and Underground Storage | 46.8 | 9.2 |
| Total Capital Expenditures | | 62.3 | 11.0 |

8. Compression Stations – significant projects related to UG’s regulated assets include strategic land purchases at 3 locations around the underground storage facilities (\$5.2M) and the Sandwich Gas Generator Overhaul (\$0.7M).
- Transmission Pipe and Underground Storage – significant projects related to UG’s regulated assets include Sarnia Expansion – Bluewater Energy Park (\$21M), Sarnia Expansion – Novacor Stn (\$10.8M), NPS 34 Trafalgar Digs (\$2.2M) and Panhandle Line Depth of Cover Mitigation (\$2M). The INTE: 156 Storage and Pool Loop: Permanent L R Facilities (\$3.4M) project has both a regulated and unregulated component due to the allocation applied to the storage pool assets. The SE 21/22 LCOR:Payne Tie-In (\$2.4M) is an unregulated project and is part of the 2nd phase of the Storage Enhancement project (EB-2021-0079) described in paragraph 7 above.

ENBRIDGE GAS
SUMMARY OF CAPITAL COST ALLOWANCE (CCA)

| Line No. | Particulars (\$000s) | Col. 1 UCC at Prior Year Filing EB-2021-0149 (a) | Col. 2 True-up from Filing to Tax Return (b) | Col. 3 UCC At Beginning of Year (c) | Col. 4 Total Additions (d) | Col. 5 Total Additions Qualifying for Accel. CCA (e) | Col. 6 Less: Lessor of Cost or Proceeds (f) | Col. 7 Eligible CCA Additions (g) | Col. 8 Depreciable UCC Balance (h) | Col. 9 Rate (%) (i) | Col. 10 CCA FY2021 (j) | Col. 11 Ending UCC (k) |
|----------|---|--|--|---|----------------------------------|--|---|---|--|------------------------------|---------------------------------|---------------------------------|
| 1. | Class | | | | | | | | | | | |
| 2. | 1 Buildings, structures and improvements, services, meters, mains | 2,298,694.5 | - | 2,298,694.5 | - | - | - | - | 2,298,694.5 | 4% | 91,947.8 | 2,206,746.7 |
| 3. | 1 Non-residential building acquired after March 19, 2007 | 118,836.9 | (386.3) | 118,450.6 | 31,673.9 | 31,047.5 | - | 46,884.5 | 165,335.0 | 6% | 9,920.1 | 140,204.4 |
| 4. | 2 Mains acquired before 1988 | 162,237.1 | (14.9) | 162,222.2 | - | - | - | - | 162,222.2 | 6% | 9,733.3 | 152,488.9 |
| 5. | 3 Buildings acquired before 1988 | 2,996.9 | - | 2,996.9 | - | - | - | - | 2,996.9 | 5% | 149.8 | 2,847.0 |
| 6. | 6 Other buildings | 80.3 | (2.0) | 78.3 | - | - | - | - | 78.3 | 10% | 7.8 | 70.5 |
| 7. | 7 Compression equipment acquired after February 22, 2005 | 490,024.8 | (9.2) | 490,015.5 | 5,851.4 | 5,789.8 | - | 8,715.5 | 498,731.0 | 15% | 74,809.7 | 421,057.3 |
| 8. | 8 Compression assets, office furniture, equipment | 191,576.3 | (190.8) | 191,385.5 | 17,583.7 | 17,583.7 | - | 26,375.5 | 217,761.0 | 20% | 43,552.2 | 165,417.0 |
| 9. | 10 Transportation, computer equipment | 28,978.1 | 42.8 | 29,020.9 | 8,412.0 | 8,412.0 | (84.2) | 12,575.9 | 41,512.6 | 30% | 12,453.8 | 24,894.9 |
| 10. | 12 Computer software, small tools | 1,521.5 | (1,521.5) | - | 60,466.4 | 57,423.4 | - | 58,944.9 | 58,944.9 | 100% | 58,944.9 | 1,521.5 |
| 11. | 13 Leasehold improvements | 673.9 | (110.1) | 563.8 | - | - | - | - | 563.8 | 0% | 212.1 | 351.7 |
| 12. | 14.1 Intangibles | 10,574.1 | (4.9) | 10,569.1 | 2,802.8 | 2,704.6 | - | 4,106.0 | 14,675.1 | 5% | 733.8 | 12,638.2 |
| 13. | 14.1 Intangibles (pre 2017) | 46,798.6 | - | 46,798.6 | - | - | - | - | 46,798.6 | 7% | 3,275.9 | 43,522.7 |
| 14. | 17 Roads, sidewalk, parking lot or storage areas | 502.6 | - | 502.6 | - | - | - | - | 502.6 | 8% | 40.2 | 462.4 |
| 15. | 38 Heavy work equipment | 10,956.3 | (28.1) | 10,928.2 | 2,587.3 | 2,587.3 | - | 3,880.9 | 14,809.1 | 30% | 4,442.7 | 9,072.7 |
| 16. | 41 Storage assets | 51,577.1 | 3,707.2 | 55,284.2 | 56,745.2 | 52,156.7 | - | 80,529.3 | 135,813.6 | 25% | 33,953.4 | 78,076.1 |
| 17. | 45 Computers - Hardware acquired after March 22, 2004 | 6.3 | - | 6.3 | - | - | - | - | 6.3 | 45% | 2.8 | 3.4 |
| 18. | 49 Transmission pipeline additions acquired after February 23, 2005 | 744,028.8 | 8,131.1 | 752,159.9 | 75,728.0 | 75,728.0 | - | 113,592.0 | 865,751.9 | 8% | 69,260.2 | 758,627.8 |
| 19. | 50 Computers hardware acquired after March 18, 2007 | 14,927.1 | 315.9 | 15,243.1 | 22,927.3 | 16,965.5 | - | 28,429.2 | 43,672.3 | 55% | 24,019.7 | 14,150.7 |
| 20. | 51 Distribution pipelines acquired after March 18, 2007 | 5,303,987.9 | (23,723.9) | 5,280,264.0 | 836,580.8 | 834,194.2 | - | 1,252,484.7 | 6,532,748.7 | 6% | 391,964.9 | 5,724,879.9 |
| 20. | Total | 9,478,979.1 | (13,794.8) | 9,465,184.3 | 1,121,359.0 | 1,104,592.6 | (84.2) | 1,636,518.3 | 11,101,618.5 | | 829,425.1 | 9,757,034.0 |

ACCOUNTS NOT BEING REQUESTED FOR CLEARANCE

1. The Company is not seeking clearance of the following accounts in this proceeding. For the following accounts, Enbridge Gas will carry the balances forward and seek clearance in appropriate future proceedings:
 - Accounting Policy Changes Deferral Account - EGI
 - Tax Variance Deferral Account – Integration-related Balances - EGI
 - Impacts Arising from the COVID-19 Emergency Deferral Account - EGI
 - Incremental Capital Module Deferral Account - EGD Rate Zone
 - Incremental Capital Module Deferral Account - Union Rate Zones

2. The following accounts of Enbridge Gas have zero balances and are therefore not requested for clearance:
 - IRP Capital Costs Deferral Account - EGI
 - Earnings Sharing Mechanism Deferral Account - EGI
 - Expansion of Natural Gas Distribution Systems Variance Account - EGI

ENBRIDGE GAS – ACCOUNTING POLICY CHANGES DEFERRAL ACCOUNT
(APCDA) (No. 179-381)

1. On August 30, 2018 the Ontario Energy Board (OEB) issued its Decision and Order for the amalgamation and rate setting mechanism (the MAADs Decision) approving the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) and the rate-setting framework¹. In its Decision, the OEB established a deferral account to record the impact of any accounting changes required as a result of amalgamation that affect the revenue requirement.² The OEB approved wording of the accounting order for the Accounting Policy Changes Deferral Account (APCDA) effective January 1, 2019 in its Decision and Order on Enbridge Gas' 2019 Rates application³.
2. As per the EB-2020-0134 Decision on Settlement Proposal, as part of the settlement proposal, parties agreed to defer the review, allocation and disposition of all balances in the APCDA until the end of Enbridge Gas's deferred rebasing term (2023). Parties noted that they required more information regarding the treatment of the balances and the extent of rate harmonization post-rebasing before approval of the balances and the disposition methodology can be considered⁴.
3. The Company continues to track the annual revenue requirement impact of accounting policy changes made as of the amalgamation date, January 1, 2019, as well as any further accounting policy changes adopted since that time. The cumulative balance of the APCDA as of December 31, 2021 is a receivable of \$139.028 million, driven by the revenue requirement impact of five accounting

¹ EB-2017-0306/0307, MAAD's Decision and Order dated August 30, 2018; The Decision and Order was later amended by the OEB on September 17, 2018 with no material changes.

² EB-2017-0306/0307, MAAD's Decision and Order dated August 30, 2018, page 47.

³ EB-2018-0305, 2019 Rates Final Rate Order dated October 24, 2019, Appendix I, page 7.

⁴ EB-2020-0134, Decision on Settlement Proposal dated January 25, 2021, pages 4-5.

changes arising from (and since) amalgamation, which are detailed in the table below. The table categorizes each of the accounting policy changes, provides the cumulative opening balance as of the beginning of the period, details the current period revenue requirement impact being added to the cumulative balance, and finally provides the ending cumulative balance as of the end of the current period. The details of each item within the table below are described further in the remaining evidence presented.

| | <u>Revenue Requirement</u> | | | | | | |
|---|---------------------------------|---------------------------------|-------------------------|----------------------------|-----------------|--------------------|----------|
| | <u>\$millions</u> | | | | | | |
| | Capitalization vs Expense | Interest During Construction | Depreciation Expense | Overhead Capitalization | Subtotal | Pension Expense | Total |
| Balance at January 1, 2021 | (0.786) | 0.887 | (10.214) | (6.427) | (16.539) | 181.465 | 164.926 |
| Impact to 2021 revenue requirement: | | | | | | | |
| Expense | (3.652) | 0.076 | (4.882) | (4.735) | (13.193) | (12.033) | (25.226) |
| Cost of capital | 0.125 | 0.112 | 0.687 | 0.668 | 1.592 | - | 1.592 |
| Income tax | (0.097) | 0.274 | (1.647) | (0.794) | (2.264) | - | (2.264) |
| Total | (3.624) | 0.462 | (5.842) | (4.861) | (13.865) | (12.033) | (25.898) |
| Balance at December 31, 2021 | (4.410) | 1.349 | (16.056) | (11.288) | (30.404) | 169.432 | 139.028 |

4. Please refer to Exhibit C, Tab 1, Schedule 2 for the detailed 2021 revenue requirement calculation of the items presented above.

1. Capitalization vs Expense

5. Capitalization policies differed between EGD and Union with respect to whether the following items were capitalized or expensed as incurred:

| | <u>Union Policy</u> | <u>EGD Policy</u> | <u>EGI Policy</u> |
|---|----------------------|-------------------|----------------------|
| <ul style="list-style-type: none"> • Verification of Maximum Operating Pressure Program (“MOP”); • Customer Assets Programs (Low Pressure Delivery Meter Set and Farm Tap Programs); • Distribution Integrity Technology; • Distribution Records Management Program; and, | Expensed as incurred | Capitalized | Expensed as incurred |
| <ul style="list-style-type: none"> • Integrity Digs resulting from integrity inspections | Expensed as incurred | Capitalized | Capitalize |

6. Upon amalgamation, it was necessary for Enbridge Gas to align its capitalization policies where differences existed between legacy EGD and legacy Union. The policy alignment resulted in a net impact in 2021 between UGL and EGD Rate Zones of:

- Lower O&M expense of approximately \$3.638 million, offset by higher capitalization; and,
- Gross revenue requirement decrease, or sufficiency of \$3.624 million.

2. Interest During Construction

7. Interest During Construction (IDC) is a cost of constructing an asset which is included in the cost of property plant and equipment capitalized.⁵ IDC is recovered in rates through depreciation expense, along with a return on rate base over the life of

⁵ ASC 835-20-05-1.

the asset. Both Union and EGD capitalized IDC in accordance with US GAAP, however, IDC calculation was different in the legacy utilities, as seen below.

| | <u>Union Policy</u> | <u>EGD Policy</u> | <u>EGI Policy</u> |
|-----------|---|--|--|
| Threshold | IDC is only calculated on projects with capital spend of \$1 million or greater, and that have a duration of greater than 12 months | No threshold – applied to all capital projects regardless of size and duration | No Threshold – applied to all capital projects regardless of size and duration |
| Rate | OEB prescribed interest rate for CWIP | Weighted average cost of debt (WACD) | OEB prescribed interest rate for CWIP |

8. Upon amalgamation, it was necessary for Enbridge Gas to align its accounting treatment of IDC. The policy alignment resulted in the following for 2021:
- Total 2021 net gross revenue requirement increase, or deficiency of \$0.711 million.
 - A 2020 true-up to the EGD IDC WACD rate in 2021 resulted in a revenue requirement decrease, or sufficiency of \$0.249 million.

3. Depreciation Expense

9. Depreciation rates for Union and EGD are based on depreciation studies that were approved by the OEB in prior proceedings. The respective depreciation studies for each EGD and Union Rate Zones continue to be used by Enbridge Gas.
10. Upon amalgamation, it was necessary for Enbridge Gas to align the depreciation policies of legacy EGD and legacy Union Gas with respect to how depreciation on assets is calculated.

| <u>Union Policy</u> | <u>EGD Policy</u> | <u>EGI Policy</u> |
|--|--|--|
| Half year of depreciation in the first and last year of service, regardless of month the asset went into service | Begin depreciation the month after the asset goes into service, and stops the month after retirement | Begin depreciation the month after the asset goes into service, and stops the month after retirement |

11. Since many projects go into service late in the year, the EGD/Enbridge Gas policy would typically result in a lower first year depreciation expense than following the Union policy.

12. The policy alignment resulted in an impact in 2021 specific only to the UGL Rate Zone of:

- A decrease in depreciation expense of approximately \$4.882 million; and,
- A gross revenue requirement decrease, or sufficiency of \$5.842 million.

4. Overhead Capitalization

13. Following amalgamation, the Company sought to harmonize its overhead capitalization methodology and retained Ernst and Young (EY) to carry out the study. EY's assessment was informed by historical legacy approaches, the amalgamated structure, US GAAP, the OEB's Uniform System of Accounts, and Enbridge's Enterprise Capitalization Policy. Recommendations of the study were implemented in January 2020. The study grouped costs into Operations Costs, Business Costs, Support Costs, and Pension and Benefits, each with their own capitalization treatment to more directly link with causal determinants of cost.

14. Prior to this harmonization, capitalized overheads in the legacy EGD approach were determined by the application of Departmental Labour Costs (DLC) rates and Administrative & General (A&G) rates to support costs for capital work in field operations and business support operations, as well as administrative functions that

support the overall business. In legacy UG, annual updates were carried out for support groups where capitalization rates were derived from time spent on capital activity.

15. The APCDA isolates the impact of the overhead capitalization policy change. The calculation takes the annual O&M spend with the new harmonized rates and subtracts from it O&M spend using the legacy rates to determine the APCDA impact. The policy change results in a decrease in O&M and offsetting increase in capitalized overheads, with the revenue requirement impact recorded in the APCDA. The net impact in 2021 between UGL and EGD Rate Zones was:

- Lower net OM&A expenses of \$5.4 million (offset by higher capitalization of overheads); and,
- A gross revenue requirement decrease, or sufficiency of \$4.861 million

5. Pension Expense – Unamortized Actuarial Gains/Losses and Prior Service Costs

16. Prior to December 31, 2018, Union recorded actuarial gains/losses and past service costs (Actuarial Losses) in Accumulated Other Comprehensive Income (AOCI) and amortized the balance over the expected average remaining service life (EARSL) of employees in accordance with ASC 715-30-35-24. This amortization expense was part of pension cost that was recognized annually and included in the forecast that underpinned rates. As a result of the Enbridge Inc. (EI) and Spectra merger (the Merger) on February 27, 2017, EI recorded the acquisition of Union through a purchase price allocation (PPA) in accordance with ASC 805. As a result, Union's pension assets were adjusted on EI's books to fair value and the unamortized Actuarial Losses of \$250 million were reclassified from AOCI to Goodwill. These

adjustments were not required to be pushed down⁶ and were not pushed down to the Union stand alone financial statements. Therefore, this adjustment did not impact Union financial statements or accounting at the time of the merger.

17. Approximately \$39 million of Actuarial Losses were amortized between February 27, 2017 and December 31, 2018, resulting in a balance of \$211 million remaining in Union's AOCI at amalgamation (the Amalgamation) (January 1, 2019).

18. Upon amalgamation, US GAAP required the PPA recorded by Enbridge Inc. related to Union to be pushed down into the combined financial statements of Enbridge Gas.⁷ This resulted in the remaining unamortized Actuarial Losses on Union's balance sheet to be reclassified from AOCI to Goodwill.

19. Although this appears to be a balance sheet reclassification only, the adjustment would have a significant impact on Enbridge Gas if not for regulatory accounting. AOCI is amortized as an annual expense whereas Goodwill is not. As such, this treatment would result in stranding the balance in Goodwill that would never be expensed. This is an accounting change that occurred only because of the amalgamation. Otherwise, Union would have continued to amortize Actuarial Losses as pension expense, just as it had done in the past.

⁶ *Pushdown accounting* refers to establishing a new basis of accounting in the separate financial statements of the acquired entity (or acquiree) after it is acquired. The acquisition adjustments recorded by the acquirer in a business combination under ASC Topic 805 are pushed down to the acquiree's separate financial statements.

⁷ In accordance with ASC 805-50-30-5: "When accounting for a transfer of assets or exchange of shares between entities under common control, the entity that receives the net assets or the equity interests shall initially measure the recognized assets and liabilities transferred at their carrying amounts in the accounts of the transferring entity at the date of transfer. If the carrying amounts of the assets and liabilities transferred differ from the historical cost of the parent of the entities under common control, for example, because pushdown accounting had not been applied, then the financial statements of the receiving entity shall reflect the transferred assets and liabilities at the historical cost of the parent of the entities under common control."

20. The change in accounting policy has not altered the fact that Union has incurred the Actuarial Losses and should recover these costs over time, as is currently approved by the OEB. As noted previously, the balances represent the accumulation of Actuarial Losses incurred in relation to the pension assets that Enbridge Gas needs to continue to fund through cash contributions to the pension plans. Enbridge Gas's funding requirements do not change simply because the accounting treatment has changed. Therefore, continued recovery in rates through the deferred rebasing period is appropriate and is consistent with the OEB's approved approach for utilities. As noted in the *"Report of the Ontario Energy Board – Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs – EB-2015-0040,"* accrual based accounting for pensions under ASC 715 would result in a match to actual cash contributions by the end of the life of the plans.
21. Accordingly, Enbridge Gas adjusted the opening balance sheet at January 1, 2019, to record the \$211 million balance previously recognized as AOCI in the financial records of Enbridge Gas as a regulatory asset (within the APCDA), instead of Goodwill. Enbridge Gas continues to draw down the regulatory asset by amortizing this balance as part of pension expense resulting in a regulatory asset balance of \$169 million recognized in the APCDA at December 31, 2021. By continuing to follow this approach, Enbridge Gas ensures that its results during the deferred rebasing period reflect the accrual based pension expense recognized annually through amortization of the noted balance.
22. As noted in the EB-2020-0134 Interrogatory Response to LPMA⁸, the amortization of actuarial gains/losses and past service costs is a component of accrual-based pension expense. Base rates for both the EGD and Union rate zones include a

⁸ EB-2020-0134, Exhibit I.LPMA.4, page 2.

provision for accrual-based pension expenses as part of O&M. As communicated previously, commencing in 2019, the amortization of the unamortized actuarial gains/losses and past service costs through a drawdown of the pension balance in the APCDA results in the amortization continuing to form part of Enbridge Gas's overall pension expense, consistent to amortization that would have occurred prior to amalgamation.

23. Enbridge Gas proposes to continue the annual amortization and inclusion as part of the accrual based pension costs recognized as part of O&M expense (consistent with the amortization of actuarial gains/losses and past service costs incurred after the Enbridge/Spectra merger in 2017). This proposal will draw down the balance in the APCDA throughout the deferred rebasing period and will result in the recognition of annual pension expenses consistent with amounts that would have been recognized had the accounting change not been required (i.e. utility earnings are not impacted).
24. As indicated in 2019 and 2020, in a continuing effort to manage the impact to ratepayers, Enbridge Gas is continuing with this approach throughout the deferred rebasing period and will propose a methodology for disposal of the residual balance in the APCDA related to pension costs at December 31, 2023, as part of rebasing.

ENBRIDGE GAS - TAX VARIANCE DEFERRAL ACCOUNT

1. Establishment of the Enbridge Gas Inc. - Tax Variance Deferral Account was approved in the OEB's 2019 Rates (EB-2018-0305) Final Rate Order¹. The purpose of this account is to record 50% of the revenue requirement impact of any tax rate changes, versus the tax rates included in rates that affect Enbridge Gas. In accordance with the OEB's July 25, 2019 letter, *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance*, also accumulated in this account is 100% of the revenue requirement impact of any changes in Capital Cost Allowance (CCA) that are not reflected in base rates. This includes impacts related to Bill C-97 CCA rule changes, which became effective November 21, 2018, as well as any future CCA changes instituted by relevant regulatory or taxation bodies. Tax rate and CCA rule change impacts recorded in the account will, however, exclude tax rate and rule change impacts that are captured through other deferral account mechanisms (i.e., through the Incremental Capital Module Deferral Account and respective Capital Pass-through Project Deferral Accounts).

¹ EB-2018-0305, Final Rate Order dated October 24, 2019, Appendix I, page 10.

2. The balance in the Enbridge Gas Tax Variance Deferral Account at the end of 2021 is comprised of the following:

| | |
|--|------------------|
| a. 2020 True up to T2 Filing balance ² | \$0.468 million |
| b. 2021 Non-integration related balance ³ | \$18.694 million |
| c. 2020 Integration related balance ⁴ | \$3.736 million |
| d. 2021 Integration related balance ⁵ | \$10.463 million |
| Total Balance | \$33.361 million |

3. As noted above, the balance requested for clearance within this proceeding is a credit of \$19.163 million⁶, plus forecast interest of \$0.227 million, for a total of \$19.390 million. Of the principal balance in the account, \$0.468 million relates to a true-up of the 2020 accelerated CCA impact, while \$18.694 million relates to the 2021 accelerated CCA impact. The 2020 true-up amount reflects the impact of a variance between the 2020 qualifying additions captured in the 2020 Enbridge Gas Tax Variance Deferral Account examined in the EB-2021-0149 proceeding, and the final 2020 qualifying additions supporting EGI's 2020 tax filing. The accelerated CCA impacts of Bill C-97 were the only tax rate changes that impacted 2021.
4. As noted in the account description, the Tax Variance Deferral Account does not include the accelerated CCA impacts related to capital pass-through and incremental capital module projects, which have been reflected in the determination of variances recorded in deferral accounts associated with those respective projects.

² Seeking approval to dispose of balance in this proceeding.

³ Seeking approval to dispose of balance in this proceeding.

⁴ Balance to be carried forward through end of 2023 per direction in EB-2021-0149 Settlement Decision.

⁵ Balance to be carried forward through end of 2023 in line with decision on 2020 integration related balance.

⁶ Sum of \$0.468 million + \$18.694 million.

5. Consistent with the OEB's EB-2021-0149 Decision and Order, dated January 27, 2021, the Tax Variance Deferral Account balance also includes the balances above that relate to accelerated CCA impacts of capital additions related to amalgamation/integration capital projects. Please see Exhibit C, Tab 1, Schedule 3 for continuity schedules supporting the calculation of the 2020 and 2021 accelerated CCA impacts of capital additions related to amalgamation/integration capital projects. The associated impacts of the annual integration related capital expenditures in 2020 and 2021 can be found in Exhibit B, Tab 3, Schedule 2. As per the direction in the Decision and Order, EGI will hold these cumulative balances in the account through 2023 and propose disposition within EGI's 2024 rebasing application.

1. Income Tax - Bill C-97 (Accelerated CCA)

6. To calculate the annual income tax (or earnings) impact of accelerated CCA, Enbridge Gas has maintained a continuity of the 2018 – 2021 total annual capital additions which have qualified for accelerated CCA, and then removed the annual additions related to capital pass-through and incremental capital module. For the remaining qualifying additions, the cumulative annual CCA has been calculated utilizing the accelerated rates and compared against the cumulative annual CCA calculated at the non-accelerated rates. The annual income tax (or earnings) impact of the variance between the two methodologies was then grossed-up for taxes to determine the annual revenue requirement impact. These annual impacts, representing 100% of the revenue requirement impact, have been recorded each year in the Enbridge Gas Inc. – Tax Variance Deferral Account. Please see Exhibit C, Tab 1, Schedule 3 for continuity schedules supporting the calculation of the 2021 accelerated CCA impact.

ENBRIDGE GAS – INTEGRATED RESOURCE PLANNING OPERATING COSTS
DEFERRAL ACCOUNT

1. On July 22, 2021, the OEB released its Decision and Order (EB-2020-0091) for Enbridge Gas' Integrated Resource Planning (IRP) Proposal. In this Decision, the OEB approved the establishment of an IRP Operating Costs Deferral Account for all IRP operations, maintenance, and administrations costs, and a separate IRP Capital Costs Deferral Account for IRP project plan costs.
2. On August 12, 2021, Enbridge Gas filed its draft accounting orders for the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account. On September 2, 2021, the OEB found that the draft accounting orders were consistent with the Decision and Order and approved the accounts as filed.
3. The purpose of the IRP Operating Costs Deferral Account, as established in the OEB's EB-2020-0091 Decision and Order, is to record incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Operating costs associated with approved IRP Plans would also include all enabling payments to service providers, made as part of the IRP Plans.
4. The balance in the 2021 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of \$0.058 million, plus forecast interest of \$0.0005 million, for a total of \$0.058 million. This amount is attributable to incremental Enbridge Gas staff salaries for IRP related work performed in 2021. 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

¹ EB-2020-0091, Decision and Order, page 71.

² EB-2020-0091, Decision and Order, page 75.

5. Since, this application is the first opportunity for Enbridge Gas to propose a rate allocation methodology for the IRP Operating Cost Deferral Account at Exhibit F, Tab 1, the account is being submitted for clearance despite the relatively modest amount incurred in 2021.

**ENBRIDGE GAS
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES**

| | | | | Col. 1 | Col. 2 | Col. 3 | Col. 4 |
|---|---|---------------------------|------|------------------------|-----------------------|--|--------------|
| | | | | | | Forecast for clearance at January 1, 2023 | |
| Line No. | Account Description | Account Acronym | | Principal (\$000's) | Interest (\$000's) | Total (\$000's) | Reference |
| <u>EGD Rate Zone Commodity Related Accounts</u> | | | | | | | |
| 1. | Storage and Transportation D/A | 2021 S&TDA | | 7,942.5 | 97.0 | 8,039.5 | D-1, Page 2 |
| 2. | Transactional Services D/A | 2021 TSDA | | (3,904.1) | (35.4) | (3,939.6) | D-1, Page 4 |
| 3. | Unaccounted for Gas V/A | 2021 UAFVA | | 753.9 | 4.5 | 758.4 | D-1, Page 6 |
| 4. | Total commodity related accounts | | | 4,792.2 | 66.2 | 4,858.4 | |
| <u>EGD Rate Zone Non Commodity Related Accounts</u> | | | | | | | |
| 5. | Average Use True-Up V/A | 2021 AUTUVA | | 14,934.3 | 135.5 | 15,069.8 | D-1, Page 10 |
| 6. | Gas Distribution Access Rule Impact D/A | 2021 GDARIDA | | - | - | - | D-1, Page 23 |
| 7. | Deferred Rebate Account | 2021 DRA | | 4,359.4 | 53.5 | 4,412.9 | D-1, Page 12 |
| 8. | Transition Impact of Accounting Changes D/A | 2021 TIACDA | | 4,435.8 | - | 4,435.8 | D-1, Page 1 |
| 9. | Electric Program Earnings Sharing D/A | 2021 EPESDA | | - | - | - | D-1, Page 23 |
| 10. | Open Bill Revenue V/A | 2021 OBRVA | | - | - | - | D-1, Page 23 |
| 11. | Ex-Franchise Third Party Billing Services V/A | 2021 EXFTPBSVA | | - | - | - | D-1, Page 23 |
| 12. | RNG Injection Service V/A | 2021 RNGISVA | | - | - | - | D-1, Page 23 |
| 13. | OEB Cost Assessment V/A | 2021 OEBCAVA | | 2,550.3 | 31.5 | 2,581.8 | D-1, Page 13 |
| 14. | Dawn Access Costs D/A | 2021 DACDA | | 1,968.0 | 17.9 | 1,985.9 | D-1, Page 16 |
| 15. | Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif | 2021 P&OPEBFAVACPDVA | | - | - | - | D-1, Page 23 |
| 16. | Total EGD Rate Zone (for clearance) | | | 33,040.0 | 304.5 | 33,344.6 | |
| <u>Union Rate Zones Gas Supply Accounts</u> | | <u>OEB Account Number</u> | | | | | |
| 17. | Upstream Transportation Optimization | 179-131 | 2021 | 8,616.3 | 78.2 | 8,694.5 | E-1, Page 6 |
| 18. | Spot Gas Variance Account | 179-107 | 2021 | - | - | - | E-1, Page 58 |
| 19. | Unabsorbed Demand Costs Variance Account | 179-108 | 2021 | (1,665.6) | (28.3) | (1,693.9) | E-1, Page 1 |
| 20. | Base Service North T-Service TransCanada Capacity | 179-153 | 2021 | 83.5 | 0.9 | 84.4 | E-1, Page 52 |
| 21. | Total Gas Supply Accounts | | | 7,034.2 | 50.8 | 7,085.0 | |
| <u>Union Rate Zones Storage Accounts</u> | | | | | | | |
| 22. | Short-Term Storage and Other Balancing Services | 179-70 | 2021 | 3,576.9 | 32.5 | 3,609.4 | E-1, Page 8 |
| <u>Union Rate Zones Other Accounts</u> | | | | | | | |
| 23. | Normalized Average Consumption | 179-133 | 2021 | 18,997.4 | 239.4 | 19,236.8 | E-1, Page 13 |
| 24. | Deferral Clearing Variance Account | 179-132 | 2021 | (3,120.4) | (45.3) | (3,165.7) | E-1, Page 21 |
| 25. | OEB Cost Assessment Variance Account | 179-151 | 2021 | 907.1 | 11.4 | 918.5 | E-1, Page 49 |
| 26. | Unbundled Services Unauthorized Storage Overrun | 179-103 | 2021 | - | - | - | E-1, Page 58 |
| 27. | Gas Distribution Access Rule Costs | 179-112 | 2021 | - | - | - | E-1, Page 58 |
| 28. | Conservation Demand Management | 179-123 | 2021 | - | - | - | E-1, Page 58 |
| 29. | Parkway West Project Costs | 179-136 | 2021 | (603.3) | (6.4) | (609.7) | E-1, Page 25 |
| 30. | Brantford-Kirkwall/Parkway D Project Costs | 179-137 | 2021 | (45.0) | (0.4) | (45.4) | E-1, Page 29 |
| 31. | Lobo C Compressor/Hamilton-Milton Pipeline Project Costs | 179-142 | 2021 | 24.0 | 0.4 | 24.4 | E-1, Page 41 |
| 32. | Lobo D/Bright C/Dawn H Compressor Project Costs | 179-144 | 2021 | (112.1) | (3.6) | (115.7) | E-1, Page 44 |
| 33. | Burlington-Oakville Project Costs | 179-149 | 2021 | (51.0) | (0.5) | (51.5) | E-1, Page 47 |
| 34. | Panhandle Reinforcement Project Costs | 179-156 | 2021 | (3,162.0) | (35.9) | (3,197.9) | E-1, Page 53 |
| 35. | Sudbury Replacement Project | 179-162 | 2021 | - | - | - | E-1, Page 58 |
| 36. | Parkway Obligation Rate Variance | 179-138 | 2021 | - | - | - | E-1, Page 58 |
| 37. | Unauthorized Overrun Non-Compliance Account | 179-143 | 2021 | - | - | - | E-1, Page 58 |
| 38. | Pension and OPEB Forecast Accrual vs. Actual Cash Payment Dif | 179-157 | 2021 | - | (1,345.6) | (1,345.6) | E-1, Page 56 |
| 39. | Unaccounted for Gas Volume Variance Account | 179-135 | 2021 | 20,501.3 | 176.9 | 20,678.2 | E-1, Page 31 |
| 40. | Unaccounted for Gas Price Variance Account | 179-141 | 2021 | 3,358.3 | 31.8 | 3,390.1 | E-1, Page 38 |
| 41. | Total Other Accounts | | | 36,694.3 | (977.8) | 35,716.5 | |
| 42. | Total Union Rate Zones (for clearance) | | | 47,305.4 | (894.6) | 46,410.8 | |
| <u>EGI Accounts</u> | | | | | | | |
| 43. | Earnings Sharing D/A | 179-382 | 2021 | - | - | - | C-1, Page 1 |
| 44. | Tax Variance - Accelerated CCA - EGI | 179-383 | 2021 | (19,162.6) | (227.2) | (19,389.8) | C-1, Page 12 |
| 45. | IRP Operating Costs Deferral Account | 179-385 | 2021 | 57.7 | 0.5 | 58.2 | C-1, Page 15 |
| 46. | IRP Capital Costs Deferral Account | 179-386 | 2021 | - | - | - | C-1, Page 1 |
| 47. | Expansion of Natural Gas Distribution Systems V/A | 179-380 | 2021 | - | - | - | C-1, Page 1 |
| 48. | Total EGI Accounts (for clearance) | | | (19,104.9) | (226.7) | (19,331.6) | |
| 49. | Total Deferral and Variance Accounts (for clearance) | | | 61,240.5 | (816.7) | 60,423.8 | |
| <u>Not Being Requested for Clearance</u> | | | | | | | |
| 50. | Accounting Policy Changes D/A - Pension - EGI | 179-120 | 2021 | 169,431.8 | - | 169,431.8 | C-1, Page 2 |
| 51. | Accounting Policy Changes D/A - Other - EGI | 179-120 | 2019 | (1,749.5) | (52.8) | (1,802.3) | C-1, Page 2 |
| 52. | Accounting Policy Changes D/A - Other - EGI | 179-120 | 2020 | (14,789.5) | (249.4) | (15,038.9) | C-1, Page 2 |
| 53. | Accounting Policy Changes D/A - Other - EGI | 179-120 | 2021 | (13,864.6) | (168.8) | (14,033.4) | C-1, Page 2 |
| 54. | Tax Variance - Integration Capital Additions - EGI | 179-383 | 2020 | (3,736.3) | (28.6) | (3,764.8) | C-1, Page 12 |
| 55. | Tax Variance - Integration Capital Additions - EGI | 179-383 | 2021 | (10,462.6) | (80.0) | (10,542.7) | C-1, Page 12 |
| 56. | Incremental Capital Module Deferral Account - EGD | 2020 ICMDA | 2020 | (254.0) | (3.2) | (257.2) | C-1, Page 1 |
| 57. | Incremental Capital Module Deferral Account - EGD | 2021 ICMDA | 2021 | 175.5 | 2.0 | 177.5 | C-1, Page 1 |
| 58. | Incremental Capital Module Deferral Account - UGL | 179-159 | 2019 | (6,869.6) | (196.1) | (7,065.7) | C-1, Page 1 |
| 59. | Incremental Capital Module Deferral Account - UGL | 179-159 | 2020 | (5,615.4) | (91.9) | (5,707.2) | C-1, Page 1 |
| 60. | Incremental Capital Module Deferral Account - UGL | 179-159 | 2021 | (14,353.4) | (147.2) | (14,500.6) | C-1, Page 1 |
| 61. | Impacts Arising from the COVID-19 Emergency D/A - EGI | 2020 IACEDA | 2020 | 1,377.5 | 20.3 | 1,397.8 | C-1, Page 1 |
| 62. | Impacts Arising from the COVID-19 Emergency D/A - EGI | 2021 IACEDA | 2021 | 34.3 | 0.4 | 34.7 | C-1, Page 1 |
| 63. | Total of Accounts not being requested for clearance | | | 99,324.2 | (995.3) | 98,328.9 | |

| ENBRIDGE GAS SUMMARY OF ACCOUNTING POLICY CHANGES DEFERRAL ACCOUNT (NO. 179-381) UTILITY REVENUE REQUIREMENT | | | | | | | | | | | | | |
|--|---|---|---|---|---|---|---------------------------------------|--|---|---|---|----------------|--|
| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 | Col. 9 | Col. 10 | Col. 11 | Col. 12 | |
| Line No. | (\$000's) | EGD - Change from Capital to O&M | UGL - Change from O&M to Capital | Capitalization Policy Alignment - Subtotal | EGD - Change from IDC rate at WACD to Board Prescribed | UGL - Elimination of IDC Threshold | IDC Policy Alignment - Subtotal | Depreciation Expense Policy Alignment | EGD - Change in Overhead Capitalization | UGL - Change in Overhead Capitalization | Overhead Capitalization Alignment - Subtotal | APCDA Total | Actuarial Gains/Losses on UGL Pension |
| | Cost of capital | | | | | | | | | | | | |
| 1. | Rate base | (6,664.9) | 7,367.8 | 702.9 | (253.1) | 1,745.5 | 1,492.4 | 9,416.5 | (5,043.7) | 13,439.8 | 8,396.1 | 20,007.9 | - |
| 2. | Required rate of return* | 6.20% | 7.30% | | 6.20% | 7.30% | | 7.30% | 6.20% | 7.30% | | | 7.30% |
| 3. | Cost of capital* | (413.2) | 537.8 | 124.6 | (15.7) | 127.4 | 111.7 | 687.4 | (312.7) | 981.1 | 668.4 | 1,592.1 | - |
| | Cost of service | | | | | | | | | | | | |
| 4. | Gas costs | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Operation and Maintenance | 916.2 | (4,554.6) | (3,638.4) | - | - | - | - | 4,513.3 | (9,930.1) | (5,416.8) | (9,055.2) | (12,033.4) |
| 6. | Depreciation and amortization | (162.0) | 148.8 | (13.2) | (7.3) | 83.5 | 76.2 | (4,881.5) | 180.2 | 502.1 | 682.3 | (4,136.2) | - |
| 7. | Municipal and other taxes | - | - | - | - | - | - | - | - | - | - | - | - |
| 8. | Cost of service | 754.2 | (4,405.8) | (3,651.6) | (7.3) | 83.5 | 76.2 | (4,881.5) | 4,693.5 | (9,428.0) | (4,734.5) | (13,191.4) | (12,033.4) |
| | Income taxes on earnings | | | | | | | | | | | | |
| 9. | Excluding tax shield | (128.3) | 1,018.3 | 890.0 | 781.2 | (430.4) | 350.8 | - | (670.3) | 1,267.4 | 597.1 | 1,837.9 | 3,188.9 |
| 10. | Tax shield provided by interest expense | 51.6 | (78.1) | (26.5) | 2.0 | (18.5) | (16.5) | (99.8) | 39.0 | (142.5) | (103.5) | (246.3) | - |
| 11. | Income taxes on earnings | (76.7) | 940.2 | 863.5 | 783.2 | (448.9) | 334.3 | (99.8) | (631.3) | 1,124.9 | 493.6 | 1,591.6 | 3,188.9 |
| | Taxes on (def) / suff. | | | | | | | | | | | | |
| 12. | Gross (def.) / suff. | (360.0) | 3,983.7 | 3,623.7 | (1,034.3) | 323.7 | (710.6) | 5,842.0 | (5,101.4) | 9,961.9 | 4,860.5 | 13,615.6 | 12,033.4 |
| 13. | Net (def.) / suff. | (264.6) | 2,928.0 | 2,663.4 | (760.2) | 237.9 | (522.3) | 4,293.9 | (3,749.5) | 7,322.0 | 3,572.5 | 10,007.5 | 8,844.5 |
| 14. | Taxes on (def.) / suff. | 95.4 | (1,055.7) | (960.3) | 274.1 | (85.8) | 188.3 | (1,548.1) | 1,351.9 | (2,639.9) | (1,288.0) | (3,608.1) | (3,188.9) |
| 15. | Revenue requirement | 359.7 | (3,983.5) | (3,623.8) | 1,034.3 | (323.8) | 710.5 | (5,842.0) | 5,101.4 | (9,961.9) | (4,860.5) | (13,615.8) | (12,033.4) |
| 16. | Gross revenue (def.) / suff. | (359.7) | 3,983.5 | 3,623.8 | (1,034.3) | 323.8 | (710.5) | 5,842.0 | (5,101.4) | 9,961.9 | 4,860.5 | 13,615.8 | 12,033.4 |
| 2020 True-Up to EGD IDC WACD rate | | | | | | | | | | | | 248.8 | |
| Total Booked to 2021 APCDA | | | | | | | | | | | | 13,864.6 | |

*Union rate zones 2013 Board-approved rate of return is 7.3% and EGD rate zone 2018 Board-approved rate of return is 6.2%.

ENBRIDGE GAS

CALCULATION OF THE BILL C-97 ACCELERATED CCA IMPACT TO BE RECORDED IN THE TAX VARIANCE DEFERRAL ACCOUNT

| 2018 Year-End | | Opening UCC | Opening UCC | Total Additions | ICM & CPT | CTA | Additions | Accel. CCA | Regular CCA | Rate | Accelerated | Regular | Closing UCC | Closing UCC |
|---------------|---|-------------|-------------|---------------------------|-----------|-----------|----------------------|-------------------------|-------------------------|------|-------------|------------|-------------|-------------|
| No. | Particulars (\$000s) | Accel. CCA | Regular CCA | Qualifying for Accel. CCA | Additions | Additions | Net of ICM CPT & CTA | Depreciable UCC Balance | Depreciable UCC Balance | (%) | CCA | CCA | Accel. CCA | Regular CCA |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| Class | | | | | | | | | | | | | | |
| 1. | 1 Buildings, structures and improvements, services, meters, mains | - | - | - | - | - | - | - | - | 4% | - | - | - | - |
| 2. | 1 Non-residential building acquired after March 19, 2007 | - | - | 2,952.7 | 1,724.3 | - | 1,228.4 | 1,842.6 | 614.2 | 6% | 110.6 | 36.9 | 1,117.8 | 1,191.5 |
| 3. | 2 Mains acquired before 1988 | - | - | - | - | - | - | - | - | 6% | - | - | - | - |
| 4. | 3 Buildings acquired before 1988 | - | - | - | - | - | - | - | - | 5% | - | - | - | - |
| 5. | 6 Other buildings | - | - | - | - | - | - | - | - | 10% | - | - | - | - |
| 6. | 7 Compression equipment acquired after February 22, 2005 | - | - | 7,775.4 | 4,438.3 | - | 3,337.0 | 5,005.6 | 1,668.5 | 15% | 750.8 | 250.3 | 2,586.2 | 3,086.8 |
| 7. | 8 Compression assets, office furniture, equipment | - | - | 7,616.0 | 100.0 | - | 7,516.0 | 11,274.0 | 3,758.0 | 20% | 2,254.8 | 751.6 | 5,261.2 | 6,764.4 |
| 8. | 10 Transportation, computer equipment | - | - | 1,874.7 | - | - | 1,874.7 | 2,812.0 | 937.3 | 30% | 843.6 | 281.2 | 1,031.1 | 1,593.5 |
| 9. | 12 Computer software, small tools | - | - | 11,185.5 | - | - | 11,185.5 | 11,185.5 | 5,592.7 | 100% | 11,185.5 | 5,592.7 | - | 5,592.7 |
| 10. | 13 Leasehold improvements | - | - | - | - | - | - | - | - | N/A | - | - | - | - |
| 11. | 14.1 Intangibles | - | - | 82.0 | - | - | 82.0 | 122.9 | 41.0 | 5% | 6.1 | 2.0 | 75.8 | 79.9 |
| 12. | 14.1 Intangibles (pre 2017) | - | - | - | - | - | - | - | - | 7% | - | - | - | - |
| 13. | 17 Roads, sidewalk, parking lot or storage areas | - | - | - | - | - | - | - | - | 8% | - | - | - | - |
| 14. | 38 Heavy work equipment | - | - | 823.6 | - | - | 823.6 | 1,235.4 | 411.8 | 30% | 370.6 | 123.5 | 453.0 | 700.1 |
| 15. | 41 Storage assets | - | - | 379.1 | 141.0 | - | 238.1 | 357.2 | 119.1 | 25% | 89.3 | 29.8 | 148.8 | 208.4 |
| 16. | 45 Computers - Hardware acquired after March 22, 2004 | - | - | - | - | - | - | - | - | 45% | - | - | - | - |
| 17. | 49 Transmission pipeline additions acquired after February 23, 2005 | - | - | 1,870.0 | 584.3 | - | 1,285.6 | 1,928.5 | 642.8 | 8% | 154.3 | 51.4 | 1,131.4 | 1,234.2 |
| 18. | 50 Computers hardware acquired after March 18, 2007 | - | - | 2,286.8 | - | - | 2,286.8 | 3,430.1 | 1,143.4 | 55% | 1,886.6 | 628.9 | 400.2 | 1,657.9 |
| 19. | 51 Distribution pipelines acquired after March 18, 2007 | - | - | 62,357.7 | 1,078.0 | - | 61,279.7 | 91,919.5 | 30,639.8 | 6% | 5,515.2 | 1,838.4 | 55,764.5 | 59,441.3 |
| 20. | Total | \$ - | - | 99,203.4 | 8,066.0 | - | 91,137.4 | 131,113.3 | 45,568.7 | | \$ 23,167.4 | \$ 9,586.7 | 67,970.0 | 81,550.6 |

| <u>2019 Year-End</u> | | Opening | Opening | Total Additions | ICM & CPT | CTA | Additions | Accel. CCA | Regular CCA | Rate | Accelerated | Regular | Closing | Closing |
|----------------------|---|-------------|-------------|-----------------|-----------|-----------|------------|-------------|-------------|------|--------------|-------------|------------|-------------|
| Line | Particulars (\$000s) | UCC | UCC | Qualifying for | Additions | Additions | Net of ICM | Depreciable | Depreciable | (%) | CCA | CCA | UCC | UCC |
| No. | | Accel. CCA | Regular CCA | Accel. CCA | | | CPT & CTA | UCC Balance | UCC Balance | | | | Accel. CCA | Regular CCA |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| Class | | | | | | | | | | | | | | |
| 1. | 1 Buildings, structures and improvements, services, meters, mains | - | - | - | - | - | - | - | - | 4% | - | - | - | - |
| 2. | 1 Non-residential building acquired after March 19, 2007 | 1,117.8 | 1,191.5 | 7,938.6 | 871.0 | - | 7,067.6 | 11,719.3 | 4,725.3 | 6% | 703.2 | 283.5 | 7,482.3 | 7,975.6 |
| 3. | 2 Mains acquired before 1988 | - | - | - | - | - | - | - | - | 6% | - | - | - | - |
| 4. | 3 Buildings acquired before 1988 | - | - | - | - | - | - | - | - | 5% | - | - | - | - |
| 5. | 6 Other buildings | - | - | - | - | - | - | - | - | 10% | - | - | - | - |
| 6. | 7 Compression equipment acquired after February 22, 2005 | 2,586.2 | 3,086.8 | 6,244.1 | 5,218.0 | - | 1,026.1 | 4,125.3 | 3,599.8 | 15% | 618.8 | 540.0 | 2,993.5 | 3,572.9 |
| 7. | 8 Compression assets, office furniture, equipment | 5,261.2 | 6,764.4 | 33,185.8 | 15,202.5 | - | 17,983.3 | 32,236.2 | 15,756.1 | 20% | 6,447.2 | 3,151.2 | 16,797.3 | 21,596.5 |
| 8. | 10 Transportation, computer equipment | 1,031.1 | 1,593.5 | 16,254.8 | - | - | 16,254.8 | 25,413.3 | 9,720.9 | 30% | 7,624.0 | 2,916.3 | 9,661.9 | 14,932.0 |
| 9. | 12 Computer software, small tools | - | 5,592.7 | 36,263.7 | - | - | 36,263.7 | 36,263.7 | 23,724.6 | 100% | 36,263.7 | 23,724.6 | - | 18,131.8 |
| 10. | 13 Leasehold improvements | - | - | - | - | - | - | - | - | N/A | - | - | - | - |
| 11. | 14.1 Intangibles | 75.8 | 79.9 | 3,595.8 | 1,836.0 | - | 1,759.8 | 2,715.5 | 959.8 | 5% | 135.8 | 48.0 | 1,699.8 | 1,791.7 |
| 12. | 14.1 Intangibles (pre 2017) | - | - | - | - | - | - | - | - | 7% | - | - | - | - |
| 13. | 17 Roads, sidewalk, parking lot or storage areas | - | - | - | - | - | - | - | - | 8% | - | - | - | - |
| 14. | 38 Heavy work equipment | 453.0 | 700.1 | 4,166.1 | - | - | 4,166.1 | 6,702.1 | 2,783.1 | 30% | 2,010.6 | 834.9 | 2,608.4 | 4,031.2 |
| 15. | 41 Storage assets | 148.8 | 208.4 | 735.5 | - | - | 735.5 | 1,252.1 | 576.1 | 25% | 313.0 | 144.0 | 571.3 | 799.8 |
| 16. | 45 Computers - Hardware acquired after March 22, 2004 | - | - | - | - | - | - | - | - | 45% | - | - | - | - |
| 17. | 49 Transmission pipeline additions acquired after February 23, 2005 | 1,131.4 | 1,234.2 | 90,992.5 | 55,507.0 | - | 35,485.5 | 54,359.6 | 18,977.0 | 8% | 4,348.8 | 1,518.2 | 32,268.1 | 35,201.6 |
| 18. | 50 Computers hardware acquired after March 18, 2007 | 400.2 | 1,657.9 | 29,431.1 | - | - | 29,431.1 | 44,546.9 | 16,373.5 | 55% | 24,500.8 | 9,005.4 | 5,330.5 | 22,083.6 |
| 19. | 51 Distribution pipelines acquired after March 18, 2007 | 55,764.5 | 59,441.3 | 499,719.3 | 988.6 | - | 498,730.7 | 803,860.5 | 308,806.6 | 6% | 48,231.6 | 18,528.4 | 506,263.5 | 539,643.6 |
| 20. | Total | \$ 67,970.0 | 81,550.6 | 728,527.3 | 79,623.1 | - | 648,904.2 | 1,023,194.5 | 406,002.8 | | \$ 131,197.5 | \$ 60,694.5 | 585,676.7 | 669,760.4 |

| <u>2020 Year-End</u> | | Opening | Opening | Total Additions | ICM & CPT | CTA | Additions | Accel. CCA | Regular CCA | Rate | Accelerated | Regular | Closing | Closing |
|----------------------|---|--------------|-------------|-----------------|-----------|-----------|------------|-------------|-------------|------|--------------|--------------|-------------|-------------|
| Line | Particulars (\$000s) | UCC | UCC | Qualifying for | Additions | Additions | Net of ICM | Depreciable | Depreciable | (%) | CCA | CCA | UCC | UCC |
| No. | | Accel. CCA | Regular CCA | Accel. CCA | | | CPT & CTA | UCC Balance | UCC Balance | | | | Accel. CCA | Regular CCA |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| Class | | | | | | | | | | | | | | |
| 1. | 1 Buildings, structures and improvements, services, meters, mains | - | - | - | - | - | - | - | - | 4% | - | - | - | - |
| 2. | 1 Non-residential building acquired after March 19, 2007 | 7,482.3 | 7,975.6 | 5,806.2 | 18.0 | - | 5,788.2 | 16,164.5 | 10,869.7 | 6% | 969.9 | 652.2 | 12,300.6 | 13,111.6 |
| 3. | 2 Mains acquired before 1988 | - | - | - | - | - | - | - | - | 6% | - | - | - | - |
| 4. | 3 Buildings acquired before 1988 | - | - | - | - | - | - | - | - | 5% | - | - | - | - |
| 5. | 6 Other buildings | - | - | - | - | - | - | - | - | 10% | - | - | - | - |
| 6. | 7 Compression equipment acquired after February 22, 2005 | 2,993.5 | 3,572.9 | 3,939.1 | 109.0 | - | 3,830.1 | 8,738.6 | 5,487.9 | 15% | 1,310.8 | 823.2 | 5,512.8 | 6,579.8 |
| 7. | 8 Compression assets, office furniture, equipment | 16,797.3 | 21,596.5 | 43,271.3 | 4,233.9 | - | 39,037.4 | 75,353.4 | 41,115.2 | 20% | 15,070.7 | 8,223.0 | 40,764.0 | 52,410.9 |
| 8. | 10 Transportation, computer equipment | 9,661.9 | 14,932.0 | 5,546.8 | - | - | 5,546.8 | 17,982.1 | 17,705.4 | 30% | 5,394.6 | 5,311.6 | 9,814.1 | 15,167.2 |
| 9. | 12 Computer software, small tools | - | 18,131.8 | 11,365.0 | - | 777.1 | 10,587.9 | 10,587.9 | 23,425.8 | 100% | 10,587.9 | 23,425.8 | - | 5,293.9 |
| 10. | 13 Leasehold improvements | - | - | - | - | - | - | - | - | N/A | - | - | - | - |
| 11. | 14.1 Intangibles | 1,699.8 | 1,791.7 | 2,214.1 | 199.4 | - | 2,014.7 | 4,721.9 | 2,799.1 | 5% | 236.1 | 140.0 | 3,478.5 | 3,666.5 |
| 12. | 14.1 Intangibles (pre 2017) | - | - | - | - | - | - | - | - | 7% | - | - | - | - |
| 13. | 17 Roads, sidewalk, parking lot or storage areas | - | - | - | - | - | - | - | - | 8% | - | - | - | - |
| 14. | 38 Heavy work equipment | 2,608.4 | 4,031.2 | 11,910.1 | - | - | 11,910.1 | 20,473.6 | 9,986.3 | 30% | 6,142.1 | 2,995.9 | 8,376.4 | 12,945.4 |
| 15. | 41 Storage assets | 571.3 | 799.8 | 30,035.1 | 16.0 | - | 30,019.1 | 45,600.0 | 15,809.4 | 25% | 11,400.0 | 3,952.4 | 19,190.4 | 26,866.6 |
| 16. | 45 Computers - Hardware acquired after March 22, 2004 | - | - | - | - | - | - | - | - | 45% | - | - | - | - |
| 17. | 49 Transmission pipeline additions acquired after February 23, 2005 | 32,268.1 | 35,201.6 | 80,470.1 | 8,582.4 | - | 71,887.7 | 140,099.7 | 71,145.4 | 8% | 11,208.0 | 5,691.6 | 92,947.8 | 101,397.7 |
| 18. | 50 Computers hardware acquired after March 18, 2007 | 5,330.5 | 22,083.6 | 40,091.6 | - | 18,135.0 | 21,956.6 | 38,265.5 | 33,061.9 | 55% | 21,046.0 | 18,184.1 | 6,241.1 | 25,856.2 |
| 19. | 51 Distribution pipelines acquired after March 18, 2007 | 506,263.5 | 539,643.6 | 639,216.7 | 50,127.7 | - | 589,089.1 | 1,389,897.2 | 834,188.1 | 6% | 83,393.8 | 50,051.3 | 1,011,958.8 | 1,078,681.3 |
| 20. | Total | \$ 585,676.7 | 669,760.4 | 873,866.1 | 63,286.3 | 18,912.2 | 791,667.7 | 1,767,884.3 | 1,065,594.3 | | \$ 166,759.8 | \$ 119,451.0 | 1,210,584.6 | 1,341,977.1 |

| Line No. | Particulars (\$000s) | <u>2021 Year-End</u> | | | | | | | | | | | | |
|----------|---|---------------------------|----------------------------|---|------------------------|------------------|--------------------------------------|--|---|-------------|--------------------|----------------|------------------------------|-------------------------------|
| | | Opening UCC Accel. CCA | Opening UCC Regular CCA | Total Additions Qualifying for Accel. CCA | ICM & CPT Additions | CTA Additions | Additions Net of ICM CPT & CTA | Accel. CCA Depreciable UCC Balance | Regular CCA Depreciable UCC Balance | Rate (%) | Accelerated CCA | Regular CCA | Closing UCC Accel. CCA | Closing UCC Regular CCA |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| Class | | | | | | | | | | | | | | |
| 1. | 1 Buildings, structures and improvements, services, meters, mains | - | - | - | - | - | - | - | - | 4% | - | - | - | - |
| 2. | 1 Non-residential building acquired after March 19, 2007 | 12,300.6 | 13,111.6 | 31,455.0 | - | 1,723.1 | 29,731.9 | 56,898.5 | 27,977.6 | 6% | 3,413.9 | 1,678.7 | 38,618.6 | 41,164.9 |
| 3. | 2 Mains acquired before 1988 | - | - | - | - | - | - | - | - | 6% | - | - | - | - |
| 4. | 3 Buildings acquired before 1988 | - | - | - | - | - | - | - | - | 5% | - | - | - | - |
| 5. | 6 Other buildings | - | - | - | - | - | - | - | - | 10% | - | - | - | - |
| 6. | 7 Compression equipment acquired after February 22, 2005 | 5,512.8 | 6,579.8 | 5,851.4 | - | - | 5,851.4 | 14,289.9 | 9,505.5 | 15% | 2,143.5 | 1,425.8 | 9,220.7 | 11,005.4 |
| 7. | 8 Compression assets, office furniture, equipment | 40,764.0 | 52,410.9 | 15,737.5 | 7,849.8 | 53.3 | 7,834.3 | 52,515.5 | 56,328.1 | 20% | 10,503.1 | 11,265.6 | 38,095.3 | 48,979.6 |
| 8. | 10 Transportation, computer equipment | 9,814.1 | 15,167.2 | 13,440.2 | - | - | 13,440.2 | 29,974.3 | 21,887.3 | 30% | 8,992.3 | 6,566.2 | 14,261.9 | 22,041.2 |
| 9. | 12 Computer software, small tools | - | 5,293.9 | 76,510.3 | - | 53,798.4 | 22,711.9 | 16,649.9 | 16,649.9 | 100% | 22,711.9 | 16,649.9 | - | 11,356.0 |
| 10. | 13 Leasehold improvements | - | - | - | - | - | - | - | - | N/A | - | - | - | - |
| 11. | 14.1 Intangibles | 3,478.5 | 3,666.5 | 2,802.8 | 18.9 | - | 2,784.0 | 7,654.4 | 5,058.5 | 5% | 382.7 | 252.9 | 5,879.7 | 6,197.5 |
| 12. | 14.1 Intangibles (pre 2017) | - | - | - | - | - | - | - | - | 7% | - | - | - | - |
| 13. | 17 Roads, sidewalk, parking lot or storage areas | - | - | - | - | - | - | - | - | 8% | - | - | - | - |
| 14. | 38 Heavy work equipment | 8,376.4 | 12,945.4 | 5,402.9 | - | - | 5,402.9 | 16,480.9 | 15,646.9 | 30% | 4,944.3 | 4,694.1 | 8,835.1 | 13,654.3 |
| 15. | 41 Storage assets | 19,190.4 | 26,866.6 | 54,897.2 | - | - | 54,897.2 | 101,536.3 | 54,315.2 | 25% | 25,384.1 | 13,578.8 | 48,703.6 | 68,185.0 |
| 16. | 45 Computers - Hardware acquired after March 22, 2004 | - | - | - | - | - | - | - | - | 45% | - | - | - | - |
| 17. | 49 Transmission pipeline additions acquired after February 23, 2005 | 92,947.8 | 101,397.7 | 75,856.8 | - | - | 75,856.8 | 206,733.0 | 139,326.0 | 8% | 16,538.6 | 11,146.1 | 152,266.0 | 166,108.3 |
| 18. | 50 Computers hardware acquired after March 18, 2007 | 6,241.1 | 25,856.2 | 7,950.3 | - | 14,327.6 | (6,377.3) | (3,324.8) | 22,667.5 | 55% | (1,828.6) | 12,467.1 | 1,692.5 | 7,011.7 |
| 19. | 51 Distribution pipelines acquired after March 18, 2007 | 1,011,958.8 | 1,078,681.3 | 810,728.0 | 104,174.2 | - | 706,553.7 | 2,071,789.4 | 1,431,958.2 | 6% | 124,307.4 | 85,917.5 | 1,594,205.2 | 1,699,317.6 |
| 20. | Total | \$ 1,210,584.6 | 1,341,977.1 | 1,100,632.4 | 112,042.9 | 69,902.3 | 918,687.2 | 2,577,259.4 | 1,801,320.7 | | \$ 217,493.1 | \$ 165,642.7 | 1,911,778.6 | 2,095,021.6 |

| | <u>2018</u> | <u>2019</u> | <u>2020</u> | <u>2021</u> |
|---|----------------|-----------------|-----------------|-----------------|
| CCA Variance (i) - (j) | 13,580.7 | 70,503.0 | 47,308.8 | 51,850.4 |
| Tax Rate | 26.5% | 26.5% | 26.5% | 26.5% |
| Earnings Impact of Accelerated CCA | 3,598.9 | 18,683.3 | 12,536.8 | 13,740.4 |
| Earnings Impact Grossed-up for Taxes Recorded in the TVDA | <u>4,896.4</u> | <u>25,419.4</u> | <u>17,056.9</u> | <u>18,694.4</u> |
| Balances as filed in EB-2021-0149 | <u>4,896.4</u> | <u>25,133.9</u> | <u>16,588.8</u> | <u>N/A</u> |
| variance | - | 285.5 | 468.2 | - |
| Include adjustment to 2019 balance in 2020 TVDA | - | (285.5) | 285.5 | - |
| Include adjustment to 2020 balance in 2021 TVDA | - | - | (468.2) | 468.2 |
| Revised Balances | <u>4,896.4</u> | <u>25,133.9</u> | <u>16,874.2</u> | <u>19,162.6</u> |

1 - Balance for 2019 was updated based on the change from EB-2020-0134 and Tax Filing on June 30, 2020.

2 - Balance for 2020 was updated based on the change from EB-2021-0149 and Tax Filing on June 30, 2021.

| <u>2020 Year-End - Integration Capital Additions</u> | | Opening UCC | Opening UCC | CTA | Accel. CCA | Regular CCA | Rate | Accelerated | Regular | Closing UCC | Closing UCC |
|--|---|-------------|-------------|-----------|-------------------------|-------------------------|------|-------------|------------|-------------|-------------|
| No. | Particulars (\$000s) | Accel. CCA | Regular CCA | Additions | Depreciable UCC Balance | Depreciable UCC Balance | (%) | CCA | CCA | Accel. CCA | Regular CCA |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| Class | | | | | | | | | | | |
| 1. | 1 Buildings, structures and improvements, services, meters, mains | - | - | - | - | - | 4% | - | - | - | - |
| 2. | 1 Non-residential building acquired after March 19, 2007 | - | - | - | - | - | 6% | - | - | - | - |
| 3. | 2 Mains acquired before 1988 | - | - | - | - | - | 6% | - | - | - | - |
| 4. | 3 Buildings acquired before 1988 | - | - | - | - | - | 5% | - | - | - | - |
| 5. | 6 Other buildings | - | - | - | - | - | 10% | - | - | - | - |
| 6. | 7 Compression equipment acquired after February 22, 2005 | - | - | - | - | - | 15% | - | - | - | - |
| 7. | 8 Compression assets, office furniture, equipment | - | - | - | - | - | 20% | - | - | - | - |
| 8. | 10 Transportation, computer equipment | - | - | - | - | - | 30% | - | - | - | - |
| 9. | 12 Computer software, small tools | - | - | 777.1 | 777.1 | 388.6 | 100% | 777.1 | 388.6 | - | 388.6 |
| 10. | 13 Leasehold improvements | - | - | - | - | - | N/A | - | - | - | - |
| 11. | 14.1 Intangibles | - | - | - | - | - | 5% | - | - | - | - |
| 12. | 14.1 Intangibles (pre 2017) | - | - | - | - | - | 7% | - | - | - | - |
| 13. | 17 Roads, sidewalk, parking lot or storage areas | - | - | - | - | - | 8% | - | - | - | - |
| 14. | 38 Heavy work equipment | - | - | - | - | - | 30% | - | - | - | - |
| 15. | 41 Storage assets | - | - | - | - | - | 25% | - | - | - | - |
| 16. | 45 Computers - Hardware acquired after March 22, 2004 | - | - | - | - | - | 45% | - | - | - | - |
| 17. | 49 Transmission pipeline additions acquired after February 23, 2005 | - | - | - | - | - | 8% | - | - | - | - |
| 18. | 50 Computers hardware acquired after March 18, 2007 | - | - | 18,135.0 | 27,202.5 | 9,067.5 | 55% | 14,961.4 | 4,987.1 | 3,173.6 | 13,147.9 |
| 19. | 51 Distribution pipelines acquired after March 18, 2007 | - | - | - | - | - | 6% | - | - | - | - |
| 20. | Total | \$ - | \$ - | 18,912.2 | 27,979.7 | 9,456.1 | | \$ 15,738.5 | \$ 5,375.7 | 3,173.6 | 13,536.5 |

| <u>2021 Year-End - Integration Capital Additions</u> | | Opening UCC | Opening UCC | CTA | Accel. CCA | Regular CCA | Rate | Accelerated | Regular | Closing UCC | Closing UCC |
|--|---|-------------|-------------|-----------|-------------------------|-------------------------|------|-------------|-------------|-------------|-------------|
| No. | Particulars (\$000s) | Accel. CCA | Regular CCA | Additions | Depreciable UCC Balance | Depreciable UCC Balance | (%) | CCA | CCA | Accel. CCA | Regular CCA |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| Class | | | | | | | | | | | |
| 1. | 1 Buildings, structures and improvements, services, meters, mains | - | - | - | - | - | 4% | - | - | - | - |
| 2. | 1 Non-residential building acquired after March 19, 2007 | - | - | 1,723.1 | 2,584.6 | 861.5 | 6% | 155.1 | 51.7 | 1,568.0 | 1,671.4 |
| 3. | 2 Mains acquired before 1988 | - | - | - | - | - | 6% | - | - | - | - |
| 4. | 3 Buildings acquired before 1988 | - | - | - | - | - | 5% | - | - | - | - |
| 5. | 6 Other buildings | - | - | - | - | - | 10% | - | - | - | - |
| 6. | 7 Compression equipment acquired after February 22, 2005 | - | - | - | - | - | 15% | - | - | - | - |
| 7. | 8 Compression assets, office furniture, equipment | - | - | 53.3 | 79.9 | 26.6 | 20% | 16.0 | 5.3 | 37.3 | 48.0 |
| 8. | 10 Transportation, computer equipment | - | - | - | - | - | 30% | - | - | - | - |
| 9. | 12 Computer software, small tools | - | 388.6 | 53,798.4 | 53,798.4 | 27,287.8 | 100% | 53,798.4 | 27,287.8 | - | 26,899.2 |
| 10. | 13 Leasehold improvements | - | - | - | - | - | N/A | - | - | - | - |
| 11. | 14.1 Intangibles | - | - | - | - | - | 5% | - | - | - | - |
| 12. | 14.1 Intangibles (pre 2017) | - | - | - | - | - | 7% | - | - | - | - |
| 13. | 17 Roads, sidewalk, parking lot or storage areas | - | - | - | - | - | 8% | - | - | - | - |
| 14. | 38 Heavy work equipment | - | - | - | - | - | 30% | - | - | - | - |
| 15. | 41 Storage assets | - | - | - | - | - | 25% | - | - | - | - |
| 16. | 45 Computers - Hardware acquired after March 22, 2004 | - | - | - | - | - | 45% | - | - | - | - |
| 17. | 49 Transmission pipeline additions acquired after February 23, 2005 | - | - | - | - | - | 8% | - | - | - | - |
| 18. | 50 Computers hardware acquired after March 18, 2007 | 3,173.6 | 13,147.9 | 14,327.6 | 24,665.0 | 20,311.7 | 55% | 13,565.7 | 11,171.4 | 3,935.5 | 16,304.0 |
| 19. | 51 Distribution pipelines acquired after March 18, 2007 | - | - | - | - | - | 6% | - | - | - | - |
| 20. | Total | \$ 3,173.6 | \$ 13,536.5 | 69,902.3 | 81,127.9 | 48,487.6 | | \$ 67,535.2 | \$ 38,516.2 | 5,540.7 | 44,922.6 |

| | <u>2020</u> | <u>2021</u> |
|--|----------------|-----------------|
| CCA Variance (i) - (j) | 10,362.8 | 29,019.0 |
| Tax Rate | 26.5% | 26.5% |
| Earnings Impact of Accelerated CCA | 2,746.1 | 7,690.0 |
| Earnings Impact Grossed-up for Taxes Related to Integrated Capital Additions | <u>3,736.3</u> | <u>10,462.6</u> |

2022 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL
ACCOUNT – EGD RATE ZONE

1. The purpose of the Transition Impact of Accounting Changes Deferral Account (TIACDA) is to track the un-cleared Other Post Employment Benefit (OPEB) costs which the OEB has approved for recovery. Within EB-2011-0354, the OEB approved the recovery of OPEB costs, which were forecast to be \$90 million at the end of 2012, evenly over a 20-year period, commencing in 2013. The OPEB costs needed to be recognized as a result of EGD having to account for post-employment expenses on an accrual basis, upon transition to USGAAP for corporate reporting purposes in 2012. The use of USGAAP for regulatory purposes was approved within the 2013 rate proceeding, EB-2011-0354.
2. The final amount recorded in the TIACDA as of the end of 2012 was \$88.716 million. The first nine installments (for each of 2013 through 2021) of \$4.436 million each (1/20 of \$88.716 million), were approved for recovery within the EB-2013-0046, EB-2014-0195, EB-2015-0122, EB-2016-0142, EB-2017-0102, EB-2018-0131, EB-2019-0105, EB-2020-0134, and EB-2021-0149 proceedings.
3. Enbridge Gas is now requesting recovery of the tenth, or 2022 installment of the OEB-Approved TIACDA amount, in the amount of \$4.436 million (1/20 of \$88.716 million). As per the approved description and scope of the account, interest is not applicable to the balances to be cleared from the TIACDA.

2021 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT
EGD RATE ZONES

1. The purpose of the 2021 Storage & Transportation Deferral Account (S&TDA) is to record the difference between the forecast cost of Storage and Transportation included in the Company's approved rates and the actual cost of Storage and Transportation incurred by the Company. Storage and Transportation cost includes cost of service and market-based pricing.
2. The S&TDA also records the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, the S&TDA is used to record amounts received by the Company related to deferral account dispositions of other utilities deferral accounts.
3. The balance in the 2021 S&TDA that the Company is proposing to collect from customers is \$7.9 million plus interest. A detailed breakdown of the S&TDA is provided in Exhibit D, Tab 1, Schedule 1.
4. The primary driver for the balance in the 2021 S&TDA is higher than forecasted transportation prices and higher than forecasted market-based storage costs in 2021, partially offset by a \$1.6M refund from the Union rate zone as part of Union's 2019 deferral disposition. Transportation prices are determined by the OEB-approved M12 Rate Schedule.
5. As outlined in the 2021 Annual Update to the 5 Year Gas Supply Plan, Enbridge Gas purchases market-based storage services on behalf of customers in the EGD rate zone through a competitive blind storage RFP process. On January 4, 2021, Enbridge Gas initiated an RFP for market-based storage capacity with deliveries to Dawn. The RFP was conducted by Guidehouse Inc. The RFP requested offers of storage services with terms of up to 5 years commencing April 1, 2021 with firm

injections from May to September and firm withdrawals from December to March.

The RFP letter is provided as Exhibit D, Tab 1, Schedule 5.

6. Enbridge Gas required this annual replacement of third-party storage in order to reliably and cost effectively meet demand on peak winter days as well as retain late season deliverability. The RFP responses were received by Enbridge Gas on January 25, 2021 with conforming offers from three different counterparties with multiple terms, prices and injection/withdrawal parameters. The RFP manager made the recommendation and Enbridge Gas transacted based on the recommendation. Bids received and those that were selected are outlined in Confidential Exhibit D, Tab 1, Schedule 6.

2021 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT
EGD RATE ZONE

1. The concept of Transactional Services operates under the premise that if circumstances arise where the assets acquired by Enbridge Gas to meet customer demand are not fully required then those assets can be made available to generate third party revenue. Transactional Services are the optimization of these assets.
2. Transactional Services optimization can be grouped into two different categories – storage optimization and transportation optimization. Storage optimization transactions typically rely on the storage of or the loan of gas between two points in time at the same location (i.e. Dawn). Transportation optimization transactions typically rely on the exchange of gas on the day between two locations.
3. Any revenues received from Transactional Services are to be shared 90:10 between the ratepayer and the Company. The EGD rate zone rates include an upfront benefit of \$12.0 million in Transactional Services revenue that has been applied to reduce the overall costs to be collected from EGD rate zone ratepayers. The purpose of the TSDA is to capture the difference between the total ratepayer share of transactional services revenue and the amount already included in rates.
4. During 2021 the Company generated a total of \$17.5 million in net Transactional Services revenue, of which the ratepayer portion represents \$15.8 million, through a combination of Storage and Transportation Optimization. Exhibit D, Tab 1, Schedule 2 provides a breakdown of Transactional Services revenue by type of transaction, and sets out the details of the amount, \$3.8 million proposed to be credited to-customers through the disposition of the 2021 TSDA. For comparison purposes the schedule also includes amounts recorded in the applicable TSDA accounts for years 2020, 2019, 2018, and 2017.

5. The transactions that Enbridge Gas entered into in 2021 contained the three elements of Transactional Services as were described in the Company's evidence in EB-2013-0046 in that they were unplanned, the result of a Third-Party service request and were available because of temporary surplus capacity.

2021 UNACCOUNTED-FOR GAS VARIANCE ACCOUNT

EGD RATE ZONE

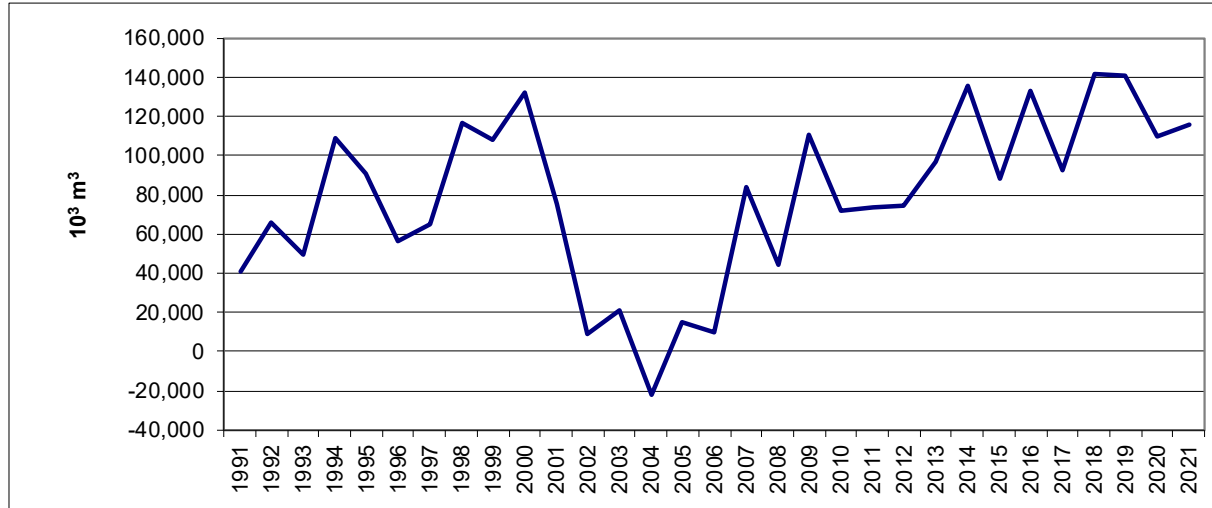
1. This evidence provides the volumetric variance underpinning the balance in the 2021 Unaccounted-For Gas Variance Account (UAFVA). It will describe the 2021 variance relative to historical Unaccounted-For Gas (UAF) volumes for the EGD rate zone.
2. UAF is the difference between natural gas delivered into the distribution system as billed by third-party transmission entities (namely, TC Energy and Union Gas¹), and natural gas consumed by the customers in the EGD rate zone and EGD own use gas and line pack gas. Owing to its residual nature, UAF cannot be measured directly. UAF can arise from meter differences, operational or external factors such as line leakage, unmetered uses, and third party damages. In addition, because gas volumes are affected by temperature and pressure, measurement is made more difficult.
3. The 2021 level of UAF for the EGD rate zone was determined to be 115,553 10³m³. The variance of 8,876 10³m³, which is the difference between actual UAF volume and the forecast UAF volume of 106,677 10³m³, underpins the \$0.7 million balance that is captured in the UAFVA. Exhibit D, Tab 1, Schedule 3 provides the detail calculations of the UAFVA balance.
4. The 2019 UAF study was filed as part of the 2020 rate application (EB-2019-0194). The report found that the primary sources for UAF include physical losses, retail meter variation and gate station meter variations. The report noted that

¹ As of January 1, 2019, Union Gas Limited and Enbridge Gas Distribution merged to become Enbridge Gas Inc.

Enbridge Gas' UAF levels are generally lower than competitive gas utilities over the past 10 years. The year-to-year fluctuations are a result of many factors including weather, estimation variation, measurement variation, and billing and accounting adjustments. The practices and initiatives to monitor and manage sources of UAF are generally consistent with those of other gas utilities. As part of the Decision and Order for the 2020 rate application (EB-2019-0194), EGI agreed to provide a "progress report" about the implementation of the UFG report recommendations in its 2022 rates application. A UFG Progress Report was filed as part of EB-2021-0148. The OEB noted that issues related to UFG were out of scope in the 2022 rate application, noting Enbridge Gas's commitment "to assess its UFG forecasting methodology in the 2024 rebasing proceeding and to include information about the implementation of the UFG Report recommendations and other activities to address UFG, and the impacts of such activities."

5. As shown in Tables 1 and 2 in the following pages, UAF within the EGD rate zone has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels especially in 2014, 2016, 2018 and 2019. The 2021 UAF level falls within the 95% confidence interval, bounded by (9,125) 10^3m^3 and 167,748 10^3m^3 .

Table 1: Unaccounted-For Gas Volumes (10^3 m^3), 1991-2021



| Table 2 | |
|--|---|
| Col.1 | Col.2 |
| Calendar Year | UAF Volumes (10 ³ m ³) |
| 1991 | 40,662 |
| 1992 | 66,028 |
| 1993 | 49,782 |
| 1994 | 108,765 |
| 1995 | 90,655 |
| 1996 | 56,739 |
| 1997 | 65,228 |
| 1998 | 116,376 |
| 1999 | 108,201 |
| 2000 | 132,021 |
| 2001 | 75,606 |
| 2002 | 9,284 |
| 2003 | 21,412 |
| 2004 | -22,406 |
| 2005 | 14,815 |
| 2006 | 10,274 |
| 2007 | 83,823 |
| 2008 | 44,424 |
| 2009 | 110,917 |
| 2010 | 72,104 |
| 2011 | 73,355 |
| 2012 | 74,762 |
| 2013 | 97,361 |
| 2014 | 135,380 |
| 2015 | 88,438 |
| 2016 | 133,112 |
| 2017 | 93,077 |
| 2018 | 142,086 |
| 2019 | 140,594 |
| 2020 | 110,234 |
| 2021 | 115,553 |
| | 1991-2021 |
| Standard deviation | 43,098 |
| Mean | 79,312 |
| Lower bound* | -9,125 |
| Upper bound* | 167,748 |
| *95% confidence interval with 27 degrees of freedom (number of observations-1) | |

2021 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT
EGD RATE ZONE

1. The purpose of this evidence is to provide information in support of the 2021 Average Use True-up Variance Account (AUTUVA) balance.
2. Exhibit D, Tab 1, Schedule 4 details the calculations of the \$14.93 million that will be collected from ratepayers. The collection is attributable to actual Rate 1 (residential) and Rate 6 (apartment, small commercial and industrial) average uses being lower than 2021 forecast levels.
3. Lower weather-normalized average uses are primarily attributable to higher actual natural gas prices and worse economic conditions than were forecast for 2021. Higher gas prices and lower employment growth have led to lower consumption for both Rate 1 and Rate 6 customers. Rate 6 customers and their consumption patterns are heavily impacted by the economic conditions under the COVID-19 pandemic. Lower GDP growth and higher (doubled) commercial vacancy rates in 2021 than were expected have been other factors which also contributed to lower average use for Rate 6 customers.
4. The purpose of the AUTUVA is to record (true-up) the revenue impact (exclusive of gas costs) of the normalized volumetric difference between the forecast of average use per customers in Rate 1 and Rate 6 and the actual weather-normalized average use experienced during the year. The revenue impact is calculated using a unit rate determined in the same manner as the impact used in the derivation of the Lost Revenue Adjustment Mechanism (LRAM).

5. As detailed in Exhibit D, Tab 1, Schedule 4, the calculation of the volumetric variance between forecast average use and actual normalized average use subtracts the volumetric impact of Demand Side Management (DSM) programs in the year. As has been the case in previous applications, since the audited actual volume savings of 2021 DSM activities will not be available until a later date, the 2021 OEB-Approved Budget DSM volumes are used as an estimate of 2021 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2021 LRAM amounts which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

2021 DEFERRED REBATE ACCOUNT

EGD RATE ZONE

1. The purpose of the 2021 Deferred Rebate Account (DRA), consistent with prior fiscal years, was to record any amounts payable to, or receivable from, EGD rate zone customers as a result of clearing Deferral and Variance Accounts, which remain outstanding due to the inability to locate such customers.
2. During 2021, the Company cleared 2017 and 2018 DSM related deferral accounts, approved as part of the EB-2020-0067 proceeding, over the April through June 2021 period. In addition, 2019 DSM related deferral accounts approved as part of the EB-2021-0072 proceeding, as well as the 2019 deferral accounts approved as part of the EB-2020-0134 proceeding, were cleared in October 2021.
3. The \$4.4 million recorded in the 2021 DRA and requested for clearance (and corresponding interest of \$53.5 thousand), reflects the outstanding amount resulting from the clearance of deferral and variance accounts in the EGD rate zone which occurred during 2021 and the inability to locate all the intended customers.

2021 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT
EGD RATE ZONE

1. The purpose of the 2021 Ontario Energy Board Cost Assessment Variance Account (OEBCAVA) was to record any material variances between the OEB costs assessed to Enbridge Gas (relevant to the EGD rate zone) through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the OEB costs which were included in EGD rate zone rates, which were determined through application of the prior Cost Assessment Model. The scope of the account is consistent with prior OEBCAVAs. However, in accordance with the EB-2020-0134 OEB-approved Settlement Proposal¹, in EGI's 2019 Earnings Sharing and Deferral Disposition proceeding, the base OEB costs assumed to be included in rates have been escalated to reflect the growth in the amount recovered through rates, which results from annual price cap adjustments and customer growth. The OEBCAVA was originally approved for establishment by an OEB letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model*.
2. The amount recorded within the 2021 OEBCAVA is \$2.550 million, plus interest of \$0.032 million for a total debit balance of \$2.582 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to EGD rate zone) in each quarter of fiscal 2021, utilizing the revised CAM, and EGD's average quarterly OEB cost assessment under the prior CAM, escalated in accordance with the EB-2020-0134 OEB-approved Settlement Proposal.
3. In order to calculate the amount to be recovered through the 2021 EGD rate zone OEBCAVA, the Company first needed to apportion the actual 2021 OEB assessed costs between the legacy rate zones. Commencing with the OEB's 2019 / 2020

¹ EB-2020-0134, Decision on Settlement Proposal, January 25, 2021, pages 5-6.

fiscal first quarter assessment (for the period April 1, 2019 through June 30, 2019), and continuing since, EGI has been receiving one consolidated quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2021 between rate zones, the assessments were prorated based on the total invoices received by each legacy utility for the OEB's 2018 / 2019 fiscal year (for the period April 1, 2018 through March 31, 2019), the final year for which the OEB issued invoices to each legacy utility. Table 1 below shows the proration of the OEB's 2018 / 2019 fiscal year assessments between each legacy utility / rate zone (59.76% EGD rate zone, 40.24% Union rate zones). Table 2 shows the apportionment of EGI's 2021 assessed costs to the EGD rate zone, and the calculation of the amount recorded in the 2021 EGD rate zone OEBCAVA.

4. To calculate the amount for recovery through the 2021 EGD rate zone OEBCAVA, the Company also needed to establish the base comparator, reflecting the OEB costs included in EGD rate zone rates, determined through application of the prior Cost Assessment Model. In accordance with the EB-2020-0134 OEB-approved Settlement Proposal, the amount reflected in rates is to be increased, or escalated, to reflect the growth in the amount recovered as a result of annual price cap adjustments and customer growth. To establish the 2021 base comparator, the Company escalated the 2020 quarterly comparator of \$0.773 million by the sum of the 2021 Price Cap Index (PCI) of 1.70%, and the EGD rate zone ICM threshold calculation Growth Factor (g) of 1.73%, which were approved as part of EGI's 2021 Rate Application (EB-2020-0181). The escalation resulted in a 2021 quarterly comparator of \$0.799 million ($\$0.773 \text{ million} * (1 + (1.70\% + 1.73\%))$). As noted above, Table 2 below shows the apportionment of EGI's actual 2021 assessed costs to the EGD rate zone, and the calculation of the amount recorded in the 2021 EGD rate zone OEBCAVA utilizing a base comparator of \$0.799 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2021 OEBCAVA, in the amount of \$2.550 million and \$0.032 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

OEB 2018/2019 Cost Assessments

| | <u>EGD</u> | <u>UGL</u> | <u>Total</u> |
|-------------------------|---------------------|---------------------|---------------------|
| Apr. 1 to Jun. 30, 2018 | 1,467,963.00 | 988,479.00 | 2,456,442.00 |
| Jul. 1 to Sep. 30, 2018 | 1,356,860.00 | 913,873.00 | 2,270,733.00 |
| Oct. 1 to Dec. 31, 2018 | 1,356,860.00 | 913,873.00 | 2,270,733.00 |
| Jan. 1 to Mar. 31, 2019 | 1,356,860.00 | 913,873.00 | 2,270,733.00 |
| | <u>5,538,543.00</u> | <u>3,730,098.00</u> | <u>9,268,641.00</u> |
| Percentage of Total | 59.76% | 40.24% | 100.00% |

Table 2

Calculation of 2021 EGD RZ OEBCAVA

| <u>Period</u> | <u>EGI Assessment</u> | <u>EGD Rate Zone Share (59.76%)</u> | <u>Average cost assessment Comparator</u> | <u>Variance to UGL Rate Zone OEBCAVA</u> |
|-------------------------|-----------------------|-------------------------------------|---|--|
| Jan. 1 to Mar. 31, 2021 | 2,497,219.00 | 1,492,231.15 | 799,494.06 | 692,737.09 |
| Apr. 1 to Jun. 30, 2021 | 2,364,191.00 | 1,412,739.31 | 799,494.06 | 613,245.25 |
| Jul. 1 to Sep. 30, 2021 | 2,379,076.00 | 1,421,633.95 | 799,494.06 | 622,139.89 |
| Oct. 1 to Dec. 31, 2021 | 2,379,076.00 | 1,421,633.95 | 799,494.06 | 622,139.89 |
| | | | | <u>2,550,262.12</u> |

2021 DAWN ACCESS COSTS DEFERRAL ACCOUNT
EGD RATE ZONE

1. The purpose of the Dawn Access Costs Deferral Account (DACDA), as established in the EB-2014-0323 Settlement Agreement, was to record for recovery the revenue requirement impact of the incremental costs incurred to implement the Dawn Transportation Service (DTS), including the costs for required system changes. In addition, in accordance with Legacy EGD's 2017 Rate Application Settlement Proposal (EB-2016-0215) the revenue requirement related to additional costs incurred to accommodate the heat value conversion modification, implemented in conjunction with the Dawn Transportation Service system development process, were also to be recorded within this account. Under the terms of the EB-2014-0323 Settlement Agreement, recovery of amounts recorded in the DACDA will be from all bundled customers, regardless of whether they are system or direct purchase and regardless of the service to which they currently subscribe, because all have the option of taking DTS if they so choose. Further details explaining the DACDA, including the recovery method, are included within Section 2.7 of the Settlement Agreement filed at Exhibit B, Tab 2, Schedule 1 of the EB-2014-0323 proceeding.
2. As was indicated in the EB-2018-0131, EB-2019-0105, EB-2020-0134, and EB-2021-0149 proceedings (in support of the clearance of the 2017 through 2020 revenue requirement amounts recorded in the 2017 through 2020 DACDAs), all incremental costs incurred by the Company to implement the DTS (and functionality for 2 additional receipt points) and heat value conversion modification were capital in nature. Capital costs of \$6.5 million were incurred to develop, test, and integrate enhancements to the functionality of Enbridge's EnTRAC and connected systems. The systems modifications were placed into service effective November 1, 2017, in conjunction with the implementation of Phase 2 of the Dawn

Access Settlement. The annual revenue requirement amounts sought for refund/recovery in association with those capital costs, includes the typical items in a cost of service revenue requirement, such as total return on rate base, including interest and return on equity, depreciation, and income taxes.

3. Within this proceeding, the Company is requesting clearance of the 2021 revenue requirement, or principal balance, of \$1.968 million (and corresponding interest of \$0.0179 million) as part of the requested one-time rate rider adjustment in January 2023, as shown in the proposed clearance balances at Exhibit C, Tab 1, Schedule 1. As indicated above, this amount represents the 2021 revenue requirement associated with the capital spending incurred to accommodate the DTS and heat value changes, which were placed into service in 2017. The Company has used the 2021 actual required capital structure within the 2021 revenue requirement calculation (consistent with the use of the actual capital structures which were utilized in determining previous revenue requirements which were approved for clearance). There will also be revenue requirement amounts to be recorded in relation to this spending in 2022, at which point the costs will be fully depreciated. The 2021 amount was slightly lower than 2020, due to a declining rate base value and lower required rate of return resulting in a lower cost of capital, but was higher than 2017 and 2018 as both years' revenue requirements benefited from a significant Capital Cost Allowance (CCA) tax deduction that does not repeat in subsequent years beyond 2018.
4. The revenue requirement sought for recovery will be allocated to the various rate classes based on the bundled annual deliveries of each rate class.
5. The determination of the 2021 DACDA revenue requirement deferral account amount and related costs are shown below. The approved 2017, 2018, 2019 & 2020 revenue requirement amounts are also shown for continuity.

| UTILITY CAPITAL STRUCTURE 2021 DACDA IMPACTS | | | | | | | | | | | | | | | |
|---|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|
| Line No. | Col. 1 | Col. 2 | Col. 3 | Col. 1 | Col. 2 | Col. 3 | Col. 1 | Col. 2 | Col. 3 | Col. 1 | Col. 2 | Col. 3 | Col. 1 | Col. 2 | Col. 3 |
| | 2017 Actual Capital Structure | 2017 Actual Capital Structure | 2017 Actual Capital Structure | 2018 Actual Capital Structure | 2018 Actual Capital Structure | 2018 Actual Capital Structure | 2019 Actual Capital Structure | 2019 Actual Capital Structure | 2019 Actual Capital Structure | 2020 Actual Capital Structure | 2020 Actual Capital Structure | 2020 Actual Capital Structure | 2021 Actual Capital Structure | 2021 Actual Capital Structure | 2021 Actual Capital Structure |
| | Component | Indicated Cost Rate | Return Component | Component | Indicated Cost Rate | Return Component | Component | Indicated Cost Rate | Return Component | Component | Indicated Cost Rate | Return Component | Component | Indicated Cost Rate | Return Component |
| | % | % | % | % | % | % | % | % | % | % | % | % | % | % | % |
| 1. Long-term debt | 56.88 | 4.86 | 2.76 | 57.05 | 4.72 | 2.69 | 61.13 | 4.44 | 2.71 | 63.07 | 4.38 | 2.76 | 60.03 | 4.35 | 2.61 |
| 2. Short-term debt | <u>5.57</u> | 1.05 | <u>0.06</u> | <u>5.65</u> | 1.81 | <u>0.10</u> | <u>2.87</u> | 2.04 | <u>0.06</u> | <u>0.93</u> | 0.60 | <u>0.01</u> | <u>3.97</u> | 0.31 | <u>0.01</u> |
| 3. | 62.45 | | 2.82 | 62.70 | | 2.80 | 64.00 | | 2.77 | 64.00 | | 2.77 | 64.00 | | 2.62 |
| 4. Preference shares | 1.55 | 2.32 | 0.04 | 1.30 | 2.98 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5. Common equity | <u>36.00</u> | 8.78 | <u>3.16</u> | <u>36.00</u> | 9.00 | <u>3.24</u> | <u>36.00</u> | 8.98 | <u>3.23</u> | <u>36.00</u> | 8.52 | <u>3.07</u> | <u>36.00</u> | 8.34 | <u>3.00</u> |
| 6. | <u>100.00</u> | | <u>6.02</u> | <u>100.00</u> | | <u>6.07</u> | <u>100.00</u> | | <u>6.01</u> | <u>100.00</u> | | <u>5.84</u> | <u>100.00</u> | | <u>5.63</u> |
| (\$ 000's) | | | | | | | | | | | | | | | |
| | 2017 | | | 2018 | | | 2019 | | | 2020 | | | 2021 | | |
| 7. Ontario Utility Income | | | 685.0 | | | (521.2) | | | (1,324.9) | | | (1,349.0) | | | (1,359.7) |
| 8. Rate base | | | 259.7 | | | 5,623.8 | | | 4,283.2 | | | 2,912.8 | | | 1,542.4 |
| 9. Indicated rate of return | | | 263.77 % | | | (9.27)% | | | (30.93)% | | | (46.31)% | | | (88.15)% |
| 10. (Def.) / suff. in rate of return | | | 257.75 % | | | (15.34)% | | | (36.94)% | | | (52.15)% | | | (93.78)% |
| 11. Net (def.) / suff. | | | 669.4 | | | (862.7) | | | (1,582.2) | | | (1,519.0) | | | (1,446.5) |
| 12. Gross (def.) / suff. | | | <u>910.7</u> | | | <u>(1,173.7)</u> | | | <u>(2,152.7)</u> | | | <u>(2,066.7)</u> | | | <u>(1,968.0)</u> |

Page Break

UTILITY RATE BASE
2021 DACDA IMPACTS

| (\$ 000's) | | | | | | |
|---------------------------------------|--|--------------|----------------|------------------|------------------|------------------|
| Line No. | | 2017 | 2018 | 2019 | 2020 | 2021 |
| Property, plant, and equipment | | | | | | |
| 1. | Cost or redetermined value | 264.4 | 6,421.6 | 6,453.2 | 6,453.2 | 6,453.2 |
| 2. | Accumulated depreciation | <u>(4.7)</u> | <u>(797.8)</u> | <u>(2,170.0)</u> | <u>(3,540.4)</u> | <u>(4,910.8)</u> |
| 3. | | <u>259.7</u> | <u>5,623.8</u> | <u>4,283.2</u> | <u>2,912.8</u> | <u>1,542.4</u> |
| Allowance for working capital | | | | | | |
| 4. | Accounts receivable merchandise finance plan | - | - | - | - | - |
| 5. | Accounts receivable rebillable projects | - | - | - | - | - |
| 6. | Materials and supplies | - | - | - | - | - |
| 7. | Mortgages receivable | - | - | - | - | - |
| 8. | Customer security deposits | - | - | - | - | - |
| 9. | Prepaid expenses | - | - | - | - | - |
| 10. | Gas in storage | - | - | - | - | - |
| 11. | Working cash allowance | <u>-</u> | <u>-</u> | <u>-</u> | <u>-</u> | <u>-</u> |
| 12. | | <u>-</u> | <u>-</u> | <u>-</u> | <u>-</u> | <u>-</u> |
| 13. | Ontario utility rate base | <u>259.7</u> | <u>5,623.8</u> | <u>4,283.2</u> | <u>2,912.8</u> | <u>1,542.4</u> |

UTILITY INCOME
2021 DACDA IMPACTS

| (\$ 000's) | | | | | |
|--------------------------------------|----------------|----------------|------------------|------------------|------------------|
| Line No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| Revenue | | | | | |
| 1. Gas sales | - | - | - | - | - |
| 2. Transportation of gas | - | - | - | - | - |
| 3. Transmission and compression | - | - | - | - | - |
| 4. Other operating revenue | - | - | - | - | - |
| 5. Other income | - | - | - | - | - |
| 6. Total revenue | <u>-</u> | <u>-</u> | <u>-</u> | <u>-</u> | <u>-</u> |
| Costs and expenses | | | | | |
| 7. Gas costs | - | - | - | - | - |
| 8. Operation and Maintenance | - | - | - | - | - |
| 9. Depreciation and amortization | 112.3 | 1,372.4 | 1,370.4 | 1,370.4 | 1,370.4 |
| 10. Municipal and other taxes | - | - | - | - | - |
| 11. Total costs and expenses | <u>112.3</u> | <u>1,372.4</u> | <u>1,370.4</u> | <u>1,370.4</u> | <u>1,370.4</u> |
| 12. Utility income before inc. taxes | (112.3) | (1,372.4) | (1,370.4) | (1,370.4) | (1,370.4) |
| Income taxes | | | | | |
| 13. Excluding interest shield | (795.4) | (809.5) | (14.1) | - | - |
| 14. Tax shield on interest expense | <u>(1.9)</u> | <u>(41.7)</u> | <u>(31.4)</u> | <u>(21.4)</u> | <u>(10.7)</u> |
| 15. Total income taxes | <u>(797.3)</u> | <u>(851.2)</u> | <u>(45.5)</u> | <u>(21.4)</u> | <u>(10.7)</u> |
| 16. Ontario utility net income | <u>685.0</u> | <u>(521.2)</u> | <u>(1,324.9)</u> | <u>(1,349.0)</u> | <u>(1,359.7)</u> |

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2021 DACDA IMPACTS

| (\$ 000's) | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|
| Line No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| 1. Utility income before income taxes | (112.3) | (1,372.4) | (1,370.4) | (1,370.4) | (1,370.4) |
| Add Backs | | | | | |
| 2. Depreciation and amortization | 112.3 | 1,372.4 | 1,370.4 | 1,370.4 | 1,370.4 |
| 3. Large corporation tax | - | - | - | - | - |
| 4. Other non-deductible items | - | - | - | - | - |
| 5. Any other add back(s) | - | - | - | - | - |
| 6. Total added back | <u>112.3</u> | <u>1,372.4</u> | <u>1,370.4</u> | <u>1,370.4</u> | <u>1,370.4</u> |
| 7. Sub total - pre-tax income plus add backs | - | - | - | - | - |
| Deductions | | | | | |
| 8. Capital cost allowance - Federal | 3,001.6 | 3,054.9 | 53.2 | - | - |
| 9. Capital cost allowance - Provincial | 3,001.6 | 3,054.9 | 53.2 | - | - |
| 10. Items capitalized for regulatory purposes | - | - | - | - | - |
| 11. Deduction for "grossed up" Part V1.1 tax | - | - | - | - | - |
| 12. Amortization of share and debt issue expense | - | - | - | - | - |
| 13. Amortization of cumulative eligible capital | - | - | - | - | - |
| 14. Amortization of C.D.E. & C.O.G.P.E. | - | - | - | - | - |
| 15. Any other deduction(s) | - | - | - | - | - |
| 16. Total Deductions - Federal | <u>3,001.6</u> | <u>3,054.9</u> | <u>53.2</u> | <u>-</u> | <u>-</u> |
| 17. Total Deductions - Provincial | <u>3,001.6</u> | <u>3,054.9</u> | <u>53.2</u> | <u>-</u> | <u>-</u> |
| 18. Taxable income - Federal | (3,001.6) | (3,054.9) | (53.2) | - | - |
| 19. Taxable income - Provincial | (3,001.6) | (3,054.9) | (53.2) | - | - |
| 20. Income tax provision - Federal | (450.2) | (458.2) | (8.0) | - | - |
| 21. Income tax provision - Provincial | <u>(345.2)</u> | <u>(351.3)</u> | <u>(6.1)</u> | <u>-</u> | <u>-</u> |
| 22. Income tax provision - combined | (795.4) | (809.5) | (14.1) | - | - |
| 23. Part V1.1 tax | - | - | - | - | - |
| 24. Investment tax credit | - | - | - | - | - |
| 25. Total taxes excluding tax shield on interest expense | <u>(795.4)</u> | <u>(809.5)</u> | <u>(14.1)</u> | <u>-</u> | <u>-</u> |
| Tax shield on interest expense | | | | | |
| 26. Rate base as adjusted | 259.7 | 5,623.8 | 4,283.2 | 2,912.8 | 1,542.4 |
| 27. Return component of debt | 2.82% | 2.80% | 2.77% | 2.77% | 2.62% |
| 28. Interest expense | 7.3 | 157.5 | 118.6 | 80.7 | 40.4 |
| 29. Combined tax rate | <u>26.500%</u> | <u>26.500%</u> | <u>26.500%</u> | <u>26.500%</u> | <u>26.500%</u> |
| 30. Income tax credit | (1.9) | (41.7) | (31.4) | (21.4) | (10.7) |
| 31. Total income taxes | <u>(797.3)</u> | <u>(851.2)</u> | <u>(45.5)</u> | <u>(21.4)</u> | <u>(10.7)</u> |

UTILITY REVENUE REQUIREMENT
2021 DACDA IMPACTS

| (\$ 000's) | | | | | |
|---|----------------|------------------|------------------|------------------|------------------|
| Line No. | 2017 | 2018 | 2019 | 2020 | 2021 |
| Cost of capital | | | | | |
| 1. Rate base | 259.7 | 5,623.8 | 4,283.2 | 2,912.8 | 1,542.4 |
| 2. Required rate of return | <u>6.02%</u> | <u>6.07%</u> | <u>6.01%</u> | <u>5.84%</u> | <u>5.63%</u> |
| 3. Cost of capital | 15.6 | 341.4 | 257.4 | 170.1 | 86.8 |
| Cost of service | | | | | |
| 4. Gas costs | - | - | - | - | - |
| 5. Operation and Maintenance | - | - | - | - | - |
| 6. Depreciation and amortization | 112.3 | 1,372.4 | 1,370.4 | 1,370.4 | 1,370.4 |
| 7. Municipal and other taxes | - | - | - | - | - |
| 8. Cost of service | <u>112.3</u> | <u>1,372.4</u> | <u>1,370.4</u> | <u>1,370.4</u> | <u>1,370.4</u> |
| Misc. & Non-Op. Rev | | | | | |
| 9. Other operating revenue | - | - | - | - | - |
| 10. Other income | - | - | - | - | - |
| 11. Misc. & Non-operating Rev. | - | - | - | - | - |
| Income taxes on earnings | | | | | |
| 12. Excluding tax shield | (795.4) | (809.5) | (14.1) | - | - |
| 13. Tax shield provided by interest expense | <u>(1.9)</u> | <u>(41.7)</u> | <u>(31.4)</u> | <u>(21.4)</u> | <u>(10.7)</u> |
| 14. Income taxes on earnings | <u>(797.3)</u> | <u>(851.2)</u> | <u>(45.5)</u> | <u>(21.4)</u> | <u>(10.7)</u> |
| Taxes on (def.) / suff. | | | | | |
| 15. Gross (def.) / suff. | 910.7 | (1,173.7) | (2,152.7) | (2,066.7) | (1,968.0) |
| 16. Net (def.) / suff. | <u>669.4</u> | <u>(862.7)</u> | <u>(1,582.2)</u> | <u>(1,519.0)</u> | <u>(1,446.5)</u> |
| 17. Taxes on (def.) / suff. | <u>(241.3)</u> | <u>311.0</u> | <u>570.5</u> | <u>547.7</u> | <u>521.5</u> |
| 18. Revenue requirement | (910.7) | 1,173.6 | 2,152.8 | 2,066.8 | 1,968.0 |
| Revenue at existing Rates | | | | | |
| 19. Gas sales | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 20. Transportation service | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 21. Transmission, compression and storage | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 22. Rounding adjustment | <u>0.0</u> | <u>(0.1)</u> | <u>0.1</u> | <u>0.0</u> | <u>0.0</u> |
| 23. Revenue at existing rates | 0.0 | (0.1) | 0.1 | 0.0 | 0.0 |
| 24. Gross revenue (def.) / suff. | <u>910.7</u> | <u>(1,173.7)</u> | <u>(2,152.7)</u> | <u>(2,066.8)</u> | <u>(1,968.0)</u> |

ACCOUNTS WITH A ZERO BALANCE

EGD RATE ZONE

1. The following 2021 accounts for the EGD Rate Zone have no balance, and are therefore not requested for clearance to customers:
 - Gas Distribution Access Rule Impact (GDARIDA) Deferral Account
 - Electric Program Earnings Sharing (EPESDA) Deferral Account
 - Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential Variance Account
 - Open Bill Revenue (OBRVA) Variance Account
 - Ex-Franchise Third Party Billing Services (EXTPBSDA) Deferral Account
 - RNG Injection Service (RNGISVA) Variance Account
2. Consistent with past annual deferral and variance account clearance proceedings, Enbridge Gas has not listed accounts that will be reviewed through other processes in Exhibit C, Tab 1, Schedule 1, and these accounts are not addressed in this proceeding. Examples include the PGVA, DSM related accounts and Federal Carbon Charge accounts.

BREAKDOWN OF THE 2021 STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT ("2021 S&TDA") - EGD RATE ZONE

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 |
|----------|---|---------------------------------------|--|---------------------------------------|-------------------------------------|--|--|
| Line No. | Contracted Union Capacity | Budgeted Daily Contract Demand Volume | Monthly Demand Toll Assumed in 2018 Budget | Forecasted Annual Cost ⁽²⁾ | Actual Daily Contract Demand Volume | Monthly Demand Toll Effective January 1, 2021 to December 31, 2021 | Balance in the 2021 S&TDA ⁽⁴⁾ |
| | (GJ) | (\$/GJ) | (\$Millions) | (GJ) | (\$/GJ) | Annual Cost ⁽³⁾ (\$Millions) | (\$Millions) |
| 1. | Union Gas Dawn to Lisgar | 67,929 | 2.865 | 2.3 | 67,929 | 3.110 | 2.5 |
| 2. | Union Gas Dawn to Parkway | 2,792,173 | 3.402 | 114.0 | 2,792,173 | 3.665 | 122.8 |
| 3. | Union Gas Dawn to Parkway - M12X | 200,000 | 4.239 | 10.2 | 200,000 | 4.530 | 10.9 |
| 4. | Union Gas F24 T | 85,000 | 0.069 | 0.1 | 85,000 | 0.073 | 0.1 |
| 5. | Union Transmission Costs | | | 126.6 | | | (9.7) |
| 6. | Dawn T Service Costs | | | (11.2) | | | 3.4 |
| 7. | Federal Carbon Costs | | | - | | | (0.9) |
| 8. | Union & Third Party Market Based Storage | | | 20.1 | | | (2.3) |
| 9. | 2019 Deferral Disposition - UG ⁽¹⁾ | | | - | | | 1.6 |
| 10. | Total | | | 135.5 | | 143.5 | (7.9) |

Notes

(1) Transportation deferral adjustments related to 2019 S&TDA reduced actual costs by \$1.6M

M12 Transport (\$1.6M), C1 Transport \$0.003M, M16 Transport (\$0.01M)

(2) Col. 1 * Col. 2 * 12

(3) Col. 4 * Col. 5 * 12

(4) Col. 3 - Col. 6

TRANSACTIONAL SERVICES REVENUE BY TYPE OF TRANSACTION ("TSDA") - EGD RATE ZONE

| Line No. | Particulars | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 |
|-------------|--------------------------------|---|---|---|---|---|
| | | 2017 Transactional Services Revenue (\$000's) | 2018 Transactional Services Revenue (\$000's) | 2019 Transactional Services Revenue (\$000's) | 2020 Transactional Services Revenue (\$000's) | 2021 Transactional Services Revenue (\$000's) |
| 1. | Storage Optimization | 1,550.1 | 423.9 | 60.7 | 0.0 | 0.0 |
| 2. | Transportation Optimization | 10,393.3 | 14,292.4 | 13,084.5 | 17,643.4 | 17,509.0 |
| 3. | Transactional Services Revenue | 11,943.5 | 14,716.2 | 13,145.2 | 17,643.4 | 17,509.0 |
| 4. | Amount Included in Rates | 12,000.0 | 12,000.0 | 12,000.0 | 12,000.0 | 12,000.0 |
| 5. | Less Ratepayer Portion of TS | 10,749.1 | 13,244.6 | 11,830.7 | 15,879.1 | 15,758.1 |
| 6. | TSDA sub-total | 1,250.9 | (1,244.6) | 169.3 | (3,879.1) | (3,758.1) |
| 7. | ETT Revenue - Rider H | 44.5 | 60.1 | 35.1 | 5.8 | 146.1 |
| 8. | TSDA Total | 1,206.4 | (1,304.7) | 134.3 | (3,884.9) | (3,904.1) |

BREAKDOWN OF THE 2021 UNACCOUNTED-FOR GAS VARIANCE ACCOUNT ("2021 UAFVA") - EGD RATE ZONE

| Line No. | Particulars | Col . 1 | Col . 2 | Col . 3 | Col . 4 | Col . 5 | Col . 6 | Col . 7 | Col . 8 | Col . 9 | Col . 10 | Col . 11 | Col . 12 | Col . 13 |
|----------|--|-------------|-------------|-------------|-------------|-------------|-----------|-----------|-----------|-----------|-----------|-------------|-------------|--------------|
| | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
| 1. | Budget UAF (10 ³ m ³) | 17,032.9 | 18,951.5 | 16,299.1 | 11,722.9 | 6,619.6 | 3,359.7 | 2,496.5 | 2,411.9 | 2,463.2 | 3,884.2 | 8,289.1 | 13,146.5 | 106,677.0 |
| 2. | PGVA Reference Price | 161.8 | 161.8 | 161.8 | 166.2 | 166.2 | 166.2 | 160.4 | 160.4 | 160.4 | 199.0 | 199.0 | 199.0 | |
| 3. | Budget UAF Dollar | 2,755,962.4 | 3,066,391.9 | 2,637,234.0 | 1,948,246.2 | 1,100,126.1 | 558,351.4 | 400,326.0 | 386,770.1 | 394,998.5 | 772,853.2 | 1,649,323.9 | 2,615,829.4 | 18,286,413.2 |
| 4. | Actual UAF (10 ³ m ³) | 16,278.8 | 17,595.3 | 14,023.7 | 9,948.2 | 7,948.8 | 4,076.4 | 3,400.6 | 3,549.0 | 3,538.1 | 3,692.1 | 8,429.5 | 11,809.8 | 104,290.4 |
| 5. | UAF Annual Variance (10 ³ m ³) ⁽¹⁾ | 1,758.0 | 1,900.2 | 1,514.5 | 1,074.3 | 858.4 | 440.2 | 367.2 | 383.3 | 382.1 | 398.7 | 910.3 | 1,275.4 | 11,262.8 |
| 6. | Total Actual UAF (10 ³ m ³) ⁽²⁾ | 18,036.9 | 19,495.5 | 15,538.1 | 11,022.5 | 8,807.3 | 4,516.6 | 3,767.8 | 3,932.2 | 3,920.2 | 4,090.8 | 9,339.9 | 13,085.2 | 115,553.2 |
| 7. | PGVA Rate | 161.8 | 161.8 | 161.8 | 166.2 | 166.2 | 166.2 | 160.4 | 160.4 | 160.4 | 199.0 | 199.0 | 199.0 | |
| 8. | Actual UAF Dollar ⁽³⁾ | 2,918,401.4 | 3,154,418.6 | 2,514,103.6 | 1,831,852.2 | 1,463,696.7 | 750,628.0 | 604,199.2 | 630,563.0 | 628,642.4 | 813,972.6 | 1,858,413.3 | 2,603,645.1 | 19,772,536.2 |
| 9. | UAFVA Volume Variance ⁽⁴⁾ | 162,439.0 | 88,026.7 | (123,130.4) | (116,394.0) | 363,570.7 | 192,276.6 | 203,873.1 | 243,792.9 | 233,643.9 | 41,119.4 | 209,089.4 | (12,184.3) | 1,486,123.1 |
| 10. | Line Pack Gas (LPG) Allocation | | | | | | | | | | | | | (406,981.7) |
| 11. | 2021 Damage Adjustment | | | | | | | | | | | | | (207,750.3) |
| 12. | 2020 Company Use True-up | | | | | | | | | | | | | (117,507.2) |
| 13. | Total 2021 UAFVA ⁽⁵⁾ | | | | | | | | | | | | | 753,883.9 |

| | | | | | | | | | | | | | | |
|------------------------------------|----------|----------|----------|----------|--------|--------|--------|--------|--------|--------|--------|----------|-----------|--|
| Notes | | | | | | | | | | | | | | |
| (1) UAF Annual Variance Allocation | 16% | 17% | 13% | 10% | 8% | 4% | 3% | 3% | 3% | 3% | 4% | 8% | 11% | |
| | 1,758.03 | 1,900.20 | 1,514.48 | 1,074.35 | 858.43 | 440.23 | 367.24 | 383.27 | 382.10 | 398.73 | 910.35 | 1,275.40 | 11,262.80 | |

(2) Line 4 + Line 5

(3) Line 6 * Line 7

(4) Line 8 - Line 3

(5) Line 9 + Line 10 + Line 11 + Line 12

2021 AVERAGE USE TRUE UP VARIANCE ACCOUNT - EGD RATE ZONE

| | Col. 1 | Col. 2 | Col. 3 | Col. 4 | Col. 5 | Col. 6 | Col. 7 | Col. 8 | Col. 9 | Col. 10 | Col. 11 |
|------------|-------------------|------------------------------|-------------------------------|------------------------|------------------------------------|-----------------------------------|-----------------------------------|-----------------------------------|--|----------------------|--|
| Rate Class | Budget Annual Use | Normalized Actual Annual Use | Normalized Usage Variance (1) | Budget Customer Meters | Normalized Volumetric Variance (2) | DSM Budget | DSM Actual | DSM Volumetric Variance (3) | Normalized Volumetric Variance Excluding DSM (4) | Unit Rate | AUTUVA: Revenue Impact, Exclusive of Gas Costs (5) |
| | (m ³) | (m ³) | (m ³) | | (10 ⁶ m ³) | (10 ⁶ m ³) | (10 ⁶ m ³) | (10 ⁶ m ³) | (10 ⁶ m ³) | (\$/m ³) | (\$Millions) |
| 1 | 2,452 | 2,404 | (48) | 2,088,486 | (99.4) | (4.8) | (4.8) | 0.0 | (99.4) | 0.0712 | (7.07) |
| 6 | 28,889 | 27,794 | (1,094) | 170,204 | (186.3) | (10.8) | (10.8) | 0.0 | (186.3) | 0.0422 | (7.86) |
| Total | | | | | | | | | | | (14.93) |

Notes

- (1) Col. 2 - Col. 1
- (2) Col. 3 * Col. 4
- (3) Col. 7 - Col. 6
- (4) Col. 5 - Col. 8
- (5) Col. 9 * Col. 10

January 4, 2021

Subject: Storage at Dawn, injections commencing April 1, 2021

Enbridge Gas Inc. operating as Enbridge Gas Distribution (Enbridge Gas) requires firm natural gas storage services with injections commencing April 1, 2021.

This storage service request is being administered by Guidehouse (formerly Navigant Consulting) on behalf of Enbridge Gas.

All questions and responses are to be directed to paul.moran@navigant.com. Due to the recent acquisition of Navigant Consulting by Guidehouse, we will continue to use the Navigant.com domain for purposes of this RFP. Do not contact Enbridge Gas directly regarding this process.

Enbridge Gas is seeking a diverse portfolio of storage services that both meet and exceed the minimum requirements below. This includes those that allow higher deliverability and access to multiple nomination windows for each gas day.

Enbridge Gas requires that these storage services meet the following specifications:

Term: Up to five (5) years commencing April 1, 2021. To encourage storage contracts term diversity, Enbridge Gas is seeking service offerings of various term lengths. The amount placed will be at Enbridge Gas's discretion.

| Term | Potential to be contracted |
|----------|----------------------------|
| 1 - year | 0 PJ's |
| 2 - year | 0 - 1 PJ's |
| 3 - year | 0 - 2 PJ's |
| 4 - year | 0 - 2 PJ's |
| 5 - year | 0 - 3 PJ's |

Location: Enbridge Gas will deliver gas to Storage Provider at Union Dawn for injection, and Storage Provider will re-deliver gas to Enbridge Gas at Union Dawn for withdrawal. If any transportation capacity is included as part of the storage offering to facilitate Dawn injections and withdrawals, please provide details.

Firm Injection Requirements: Must include the months from May 1 through Sept. 30

Firm Withdrawal Schedule: Must include the months from Dec. 1 through March 31

Responses: Should you be interested in supplying this storage service to Enbridge Gas, please complete the attached Excel form, stating the delivery points, term, MSB and service attributes with the relevant pricing, including demand, commodity charges and other items indicated.¹

The deadline to submit your proposal(s) is **2 p.m. Mountain Daylight Time on Jan. 25, 2021**, after which time Enbridge Gas will contact the parties which submitted proposals that have been selected². Please submit your proposal(s) to the attention of Paul Moran per the instructions in the enclosed attachment.

Additional Information: Enbridge Gas invites all potential participants to review a presentation that has been posted in the Storage and Transportation section of its website, within

[Presentations.](#)

*If you have questions regarding this RFP, please direct to the attention of Paul Moran at the email address provided above. The deadline for any **queries** is 12 p.m.(noon) Mountain Daylight Time on Jan. 12, 2021. All queries and responses will be provided to all parties on Jan. 15, 2021.*

Enbridge Gas will contact successful bidders following the close of the RFP process.

Yours truly,
Paul Moran
Guidehouse

¹ This storage service request may have Dodd Frank Act implications and may require specific clauses to be included in any storage agreement between the parties. Any such storage agreement will not be binding until a definitive agreement is executed by the parties.

² Please note that successful suppliers must meet all of Enbridge's credit criteria. Enbridge, in its sole discretion and for whatever reason, may accept or reject any and all proposals. Enbridge reserves the right at any time after the deadline to conduct negotiations with one or more of the bidders to the exclusion of others, and such negotiations may include changes to the storage service described in this letter.

UNABSORBED DEMAND COSTS (UDC) VARIANCE ACCOUNT
UNION RATE ZONES

1. The balance in the UDC Variance Account is a credit to ratepayers of \$1.666 million plus interest as of December 31, 2022 of \$0.028 million, for a total of \$1.694 million. The \$1.666 million balance is the difference between the actual UDC incurred by the Union Rate Zones and the amount of UDC collected in rates.

1. UDC Recovery in Rates

2. To meet customer demands across the Union rate zones and to meet the planned storage inventory levels at October 31, approved rates for the Union rate zones in 2021 included planned unutilized pipeline capacity of 11.3 PJ in Union North West, 3.1 PJ in Union North East and 0 PJ in Union South. The UDC volumes included in 2021 rates are based on the Gas Supply Plan filed in Union's Dawn Reference Price proceeding¹.
3. As discussed in the Enbridge Gas 5 Year Gas Supply Plan², in Union North, the upstream transportation capacity (long-haul, short-haul and STS) is first sized to meet the design day requirements. The amount of transportation capacity needed to meet average annual demand requirements is less than the capacity required to meet design day requirements. Therefore, a portion of contracted capacity for the Union rate zones is planned to be unutilized. In a warmer than normal year, UDC may be incurred in Union South, and additional UDC in Union North, to balance supply with lower demands. The Union North and Union South transportation portfolios are managed on an integrated basis and the pipeline to leave unutilized, if necessary, is determined based on the least cost option. In the EB-2021-0149

¹ EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.

² EB-2019-0137, page 82.

Settlement Proposal related to the disposition of the 2020 UDC Variance account, Enbridge Gas agreed:

“In future deferral and variance account clearance applications related to the deferred rebasing term, Enbridge Gas agrees that it will include evidence reporting on: UDC and transportation capacity released by rate zone, and the costs and revenues transferred between rate zones.”³

Table 1 provides the capacity released by rate zone and the associated UDC costs and/or revenue. The path released does not determine where the UDC costs or associated revenue for the releases will be allocated. Instead, the costs and revenue are allocated based on the portion of the UDC variance driven by each respective rate zone, as can be seen in Table 2.

Table 1
Capacity Released & Related Costs Incurred

| Line No. | Particulars | Union North East | Union North West | Union South | Total Franchise Area |
|----------|---------------------------------|------------------|------------------|-------------|----------------------|
| 1 | Capacity Released (TJ) | 2,953 | 5,957 | 19,631 | 28,541 |
| 2 | UDC Costs Incurred (\$000's) | 1,522 | 3,754 | 3,040 | 8,315 |
| 3 | Released UDC Capacity (\$000's) | 0 | (1,238) | (123) | (1,361) |

4. Enbridge Gas collected \$8.620 million in rates for UDC for the Union rate zones during 2021 and recorded an associated interest credit of \$0.028 million (see Table 2). Actual UDC costs in 2021 were \$8.315 million offset by \$1.361 million in released capacity value, resulting in a net cost of \$6.954 million (see Table 3).

³ EB-2021-0149, Exhibit N1, Tab 1, Schedule 1, page 15.

Actual UDC costs are allocated to Union North West, Union North East and Union South in proportion to the actual supply and demand variances which occurred in each respective area.

5. The variance between the amounts collected in rates and the actual UDC costs, including the interest credit of \$0.028 million, results in a net credit to ratepayers in the UDC Variance Account of \$1.694 million.
6. The balance applicable to sales service and bundled DP customers in Union North West is a credit of \$4.806 million and in Union North East, a credit of \$0.033 million. There is a debit of \$3.145 million applicable to sales service customers in Union South.
7. Table 2 provides the derivation of the UDC variance account balances by operational area.

Table 2
UDC Variance Account by Operational Area

| Line No. | Particulars (\$000's) | Union North East | Union North West | Union South | Total Franchise Area |
|----------|-----------------------------------|------------------|------------------|-------------|----------------------|
| 1 | UDC Collected in Rates | (1,511) | (7,109) | - | (8,620) |
| 2 | UDC Costs Incurred (Table 3) | 1,479 | 2,383 | 3,092 | 6,954 |
| 3 | Variance (line 1 + line 2) | (32) | (4,726) | 3,092 | (1,666) |
| 4 | Interest | (1) | (80) | 53 | (28) |
| 5 | (Credit)/Debit to Operations Area | (33) | (4,806) | 3,145 | (1,694) |

A description of each item in Table 2 is set out below:

1.1 UDC Collected in Rates

8. The 2021 OEB-approved rates include \$9.082 million of UDC associated with 14.4 PJ of planned unutilized pipeline capacity in Union North West and Union North East and no planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TC Energy final tolls effective January 1, 2021. On an actual basis in 2021, Enbridge Gas recovered \$8.620 million in Union North West and Union North East and \$0.0 million in Union South.

1.2 UDC Costs Incurred

9. The actual unutilized capacity in 2021 was 28.5 PJ. The level of unutilized capacity experienced in 2021 was largely due to planned unutilized capacity (and resulting UDC) and warmer than normal weather.
10. The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling \$8.315 million, partially offset, by the value of \$1.361 million generated from releasing the pipeline transportation capacity to the market. Unutilized upstream transportation capacity is released and sold on the secondary market to minimize UDC. The value generated from the transportation releases is credited to the UDC Variance Account mitigating the overall UDC impact as shown in Table 3 below.

Table 3
UDC Costs Incurred

| Line No. | Particulars (\$000's) | Union North East | Union North West | Union South | Total Franchise Area |
|-------------|------------------------------|------------------------|------------------------|----------------|----------------------------|
| 1 | UDC Costs Incurred | 1,768 | 2,849 | 3,697 | 8,315 |
| 2 | Released Capacity Revenue | (289) | (466) | (605) | (1,361) |
| 3 | Net UDC Costs (Credit)/Debit | 1,479 | 2,383 | 3,092 | 6,954 |

ACCOUNT NO. 179-131 UPSTREAM TRANSPORTATION OPTIMIZATION – UNION
RATE ZONES

1. The Upstream Transportation Optimization Deferral Account was approved by the OEB in its EB-2011-0210 Decision to capture the variance between the ratepayers' 90% share of actual net revenues from optimization activities, and the amount refunded to ratepayers in rates. The 2021 balance in this deferral account is a debit from ratepayers of \$8.616 million plus interest of \$.078 million for a total debit from ratepayers of \$8.694 million.
2. In setting rates for 2021, the OEB approved a forecast of optimization revenue of \$14.918 million. Of that amount, 90% or \$13.426 million, was credited to ratepayers in the OEB-approved 2021 rates.¹ On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited \$15.392 million in rates to ratepayers during 2021, \$1.966 million greater than the OEB-approved amount of \$13.426 million. The credit is due to actual sales service volumes exceeding the forecast sales service volumes in rates. The main driver of actual sales service volumes exceeding the forecasted amount is customer growth since 2013.
3. The Company earned \$7.529 million in net revenues from upstream transportation optimization during 2021 in the Union Rate Zones. In accordance with the OEB-approved sharing methodology, 90% of this net revenue, or \$6.776 million, is to be credited to customers. As stated above, \$15.392 million has already been credited through rates; therefore, the deferral balance is a debit from ratepayers of \$8.616 million (\$15.392 million less \$6.776 million).

¹ Detailed schedule last filed at EB-2017-0087 (2018 Rates), Draft Rate Order, Working Papers, Schedule 14, page 1. The credit of \$13.426 million to Union rate zone in-franchise customers is maintained in the setting of rates for the 2019-2023 deferred rebasing period in accordance with the approved rate-setting mechanism.

4. Exhibit E, Tab 1, Schedule 1, provides a summary of the calculation of the balance in this deferral account. 2021 actual Upstream Transportation Optimization revenue in the Union rate zones is lower than 2013 OEB-approved revenue primarily due to the elimination of the TransCanada FT-RAM program (\$5.800 million) and changing market dynamics.

ACCOUNT NO. 179-70 SHORT-TERM STORAGE AND OTHER BALANCING
SERVICES – UNION RATE ZONES

1. The Short-Term Storage and Other Balancing Services Deferral Account includes revenues from C1 Off-Peak Storage, Gas Loans, Supplemental Balancing Services and C1 Short-Term Firm Peak Storage. The deferral account compares the ratepayer share (90%) of net revenue for Short-Term Storage and Other Balancing Services with the amount credited to ratepayers in rates for Short-Term Storage and Other Balancing Services. The net revenue for Short-Term Storage and Other Balancing Services is determined by deducting the costs incurred to provide service from the gross revenue. The balance in this deferral account is a debit from ratepayers of \$3.577 million, plus interest of \$0.0325 million for a total debit from ratepayers of \$3.609 million.
2. As shown in Table 3, the balance is calculated by comparing \$0.974 million (ratepayer 90% share of the actual 2021 Short-Term Storage and Other Balancing Services net revenue of \$1.082 million) to the net revenue included in Union rate zone rates of \$4.551 million.¹ The details of the balance are found at Exhibit E, Tab 1, Schedule 2.

¹ EB-2011-0210, Decision and Rate Order, January 17, 2013, page 16.

Table 3

Deferral Summary: Short-term Storage and Other Storage Services

| <u>Line</u> | | <u>Actual</u> |
|-------------|---|----------------|
| <u>No.</u> | <u>Particulars (\$000's)</u> | <u>2021</u> |
| 1 | Net Revenue | 1,082 |
| 2 | Ratepayer Portion (90%) | 974 |
| 3 | Approved in Rates | 4,551 |
| 4 | Deferral Balance Payable to/(Collectable from) Ratepayers | <u>(3,577)</u> |

3. Actual 2021 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of \$1.075 million were \$1.425 million lower than the 2013 OEB-approved forecast of \$2.500 million.
4. The C1 Short-Term Firm Peak Storage revenues of \$1.536 million were \$6.347 million lower than the 2013 Board-approved forecast of \$7.883 million. Actual Union rate zone utility storage requirements for 2021 were 8.3 PJ higher than the 2013 OEB-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 OEB-approved to 3.0 PJ in 2021). Union rate zone customers received the value of storage directly through the use of the storage space, rather than through the sale of short-term storage.
5. Year-over-year, actual utility storage requirements for 2021 were 0.7 PJ lower than the requirement in 2020, resulting in an increase in the C1 Short-Term Peak Storage available for sale (from 2.3 PJ in 2020 to 3.0 PJ in 2021). This is a result of a decrease in the storage requirement for utility customers. The storage requirement for the general service market was calculated using the OEB-approved aggregate excess methodology. The storage requirement for the contract market was calculated specifically for each customer using either the OEB-approved aggregate excess

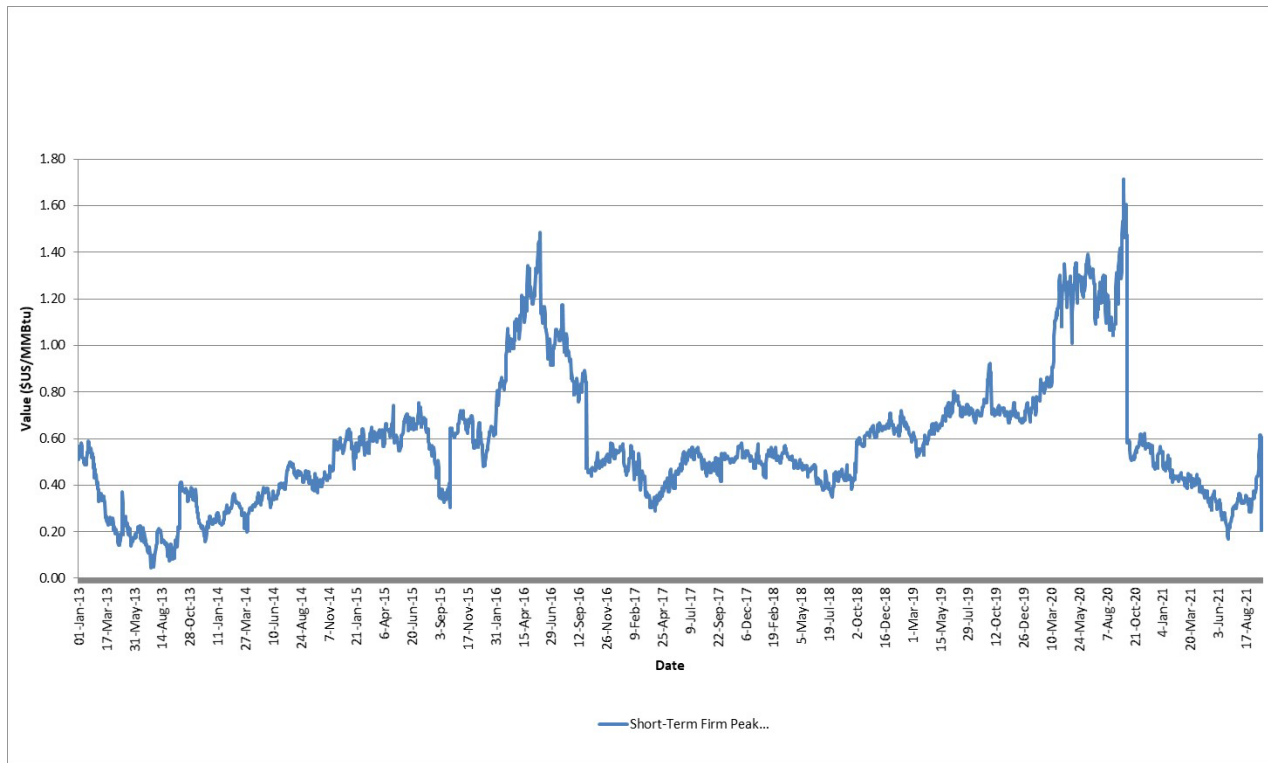
methodology, the 15 times obligated Daily Contracted Quantity (DCQ) storage methodology, or the 10 times Firm Contract Demand (CD) storage methodology (for those customers who have elected the Customer Managed Service).² Enbridge Gas has included the calculation for utility storage space requirements and the deliverability by rate class at Exhibit E, Tab 1, Schedule 2, Appendix A.³

6. The 2013 OEB-approved forecast implied an annual average value for C1 Short-Term Firm Peak Storage of \$0.70/GJ (\$7.883 million/11.3 PJ), and the actual average annual C1 Short-Term Firm Peak Storage value in 2021 was \$0.51/GJ (\$1.5 million/3.0 PJ). Please see Figure 1 for Short-Term Peak Storage values in US dollars.

² EB-2016-0245, Decision and Rate Order, Schedule 1, Settlement Proposal, page 7.

³ EB-2021-0149, Decision on Settlement Proposal, Schedule 1, Settlement Proposal, page 16.

Figure 1
Historical Short-Term Firm Peak Storage Values at Dawn 2013-2021



1. Non-Utility Storage Balances for 2021

7. In its EB-2011-0210 Decision, the OEB directed legacy Union to file a report similar to that ordered in EB-2011-0038 to monitor the inventory related to non-utility storage operations. Exhibit E, Tab 1, Schedule 3 shows the non-utility inventory balances for October and November of 2021 (for legacy Union storage).
8. During the 2021 injection season, the non-utility storage balance peaked on November 18, 2021 at 98.9% full with a balance of 126.1 PJ compared to available space of 127.6 PJ. At October 31, 2021, the date to which the Company manages its storage balance, the non-utility balance was 95.1% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2021.

9. In EB-2011-0210, the OEB further ordered Union to file a calculation for a storage encroachment payment from Union's non-utility business to Union's utility business, if Union's non-utility business encroached on Union's utility space. There was no encroachment of utility space in 2021 and therefore no calculation applies.

2. Sale of Non-Utility Storage Space

10. Enbridge Gas prioritizes the sale of its legacy Union utility storage ahead of the sale of its short-term non-utility storage and allocates short-term peak storage margins between utility and non-utility as directed by the OEB in EB-2011-0210.⁴ Margins from short-term peak storage services are proportionately split between the utility and non-utility customers based on the utility and non-utility share of the total quantity of short-term peak storage sold each calendar year. Short-term peak sales include any sale of storage space for a term of less than two storage years.
11. In 2021, Enbridge Gas sold a total of 3.0 PJ of short-term peak storage (legacy Union). The total 3.0 PJ was excess utility space, calculated by deducting 97.0 PJ of in-franchise utility requirement (as per the Gas Supply Plan) from the total 100 PJ of in-franchise utility storage. There was no sale of short-term peak storage from non-utility space. Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2021 was \$1.536 million. Details of the above sales are reflected in Exhibit E, Tab 1, Schedule 4.

⁴ EB-2011-0210, Decision and Order, pages 116-117.

ACCOUNT NO. 179-133 NORMALIZED AVERAGE CONSUMPTION (NAC)
UNION RATE ZONES

1. The purpose of the NAC deferral account is to record the variance in delivery revenue and storage revenue and costs resulting from the difference between the target NAC included in OEB-approved rates and the actual NAC for general service rate classes Rate M1, Rate M2, Rate 01 and Rate 10. As described in Union's 2014 Deferral Account Disposition¹ proceeding, including the revenue from storage rates in the NAC deferral account requires storage-related costs associated with the difference in target and actual NAC to also be included in the deferral account balance.
2. For 2021, the balance in the NAC deferral account is a debit to ratepayers of \$18.998 million plus interest of \$0.239 million for a total debit to ratepayers of \$19.237 million.
3. The NAC Deferral Account follows the same methodology agreed to by parties in Union's 2014-2018 Incentive Regulation (IR) Settlement Agreement² and as subsequently modified in Union's 2015 Rates³ proceeding.

1. Target and Actual NAC

4. The 2021 target NAC used to calculate base rates for each rate class was approved by the OEB in Enbridge Gas's 2021 Rates⁴ proceeding. The 2019 actual NAC, weather normalized using the 2021 weather normal, was used to determine the 2021 target NAC for each rate class to calculate base rates. Setting the 2021 target

¹ EB-2015-0010.

² EB-2013-0202.

³ EB-2014-0271.

⁴ EB-2020-0095.

NAC based on the 2019 actual NAC recognizes that over the two-year span to the current year, any volumes saved and lost revenues due to DSM activities will be captured by the variance between the target NAC and actual NAC. This is due to the inclusion of the DSM saved volumes within the actual reported consumption.

5. The 2021 forecast usage used to calculate Y factor unit rates for each rate class was approved by the OEB in Enbridge Gas's 2021 Rates proceeding. The unit rates for pass-through (Y factor) costs are derived based on OEB-approved cost allocation and rate design methodologies and are passed through to customers at cost.
6. The 2021 actual NAC for each rate class is weather normalized using the 2021 weather normal, which is produced using the OEB-approved weather methodology consisting of a 50:50 average of the 30-year average and the 20-year trend estimates of annual heating degree-days.
7. Table 1 provides the 2021 target NAC and 2021 actual NAC by rate class for base rates.

Table 1
2021 Target and Actual NAC - Base Rates

| <u>Line No.</u> | <u>Particulars (m³/customer)</u> | <u>Rate 01</u> | <u>Rate 10</u> | <u>Rate M1</u> | <u>Rate M2</u> |
|-----------------|---|----------------|----------------|----------------|----------------|
| | | (a) | (b) | (c) | (d) |
| 1 | 2021 Target NAC | 2,889 | 171,540 | 2,776 | 168,419 |
| 2 | 2021 Actual NAC | 2,766 | 151,411 | 2,668 | 149,840 |
| 3 | Variance (Target - Actual NAC) | 124 | 20,129 | 108 | 18,580 |

8. Table 2 provides the 2021 target and 2021 actual NAC by rate class for Y factor rates.

Table 2
2021 Target and Actual NAC - Y Factor Rates

| Line No. | Particulars (m ³ /customer) | Rate 01 | Rate 10 | Rate M1 | Rate M2 |
|----------|--|---------|---------|---------|---------|
| | | (a) | (b) | (c) | (d) |
| 1 | 2021 Target NAC | 2,830 | 166,842 | 2,692 | 169,477 |
| 2 | 2021 Actual NAC | 2,766 | 151,411 | 2,668 | 149,840 |
| 3 | Variance (Target - Actual NAC) | 64 | 15,431 | 24 | 19,637 |

2. Delivery and Storage Revenues

9. The deferral account balance is calculated by multiplying the variance between the weather normalized target NAC and the weather normalized actual NAC by the 2013 OEB-approved number of customers and the 2021 OEB-approved delivery and storage rates for each general service rate class. A credit balance in the NAC Deferral Account reflects that the actual NAC is greater than the target NAC, while a debit balance in the NAC Deferral Account reflects that the actual NAC is less than the target NAC.
10. Table 3 provides the NAC Deferral Account balances by rate class. The detailed calculation of the NAC Deferral Account balance can be found at Exhibit E, Tab 1, Schedule 6.

Table 3
2021 NAC Deferral Account

Line

| <u>No.</u> | <u>Particulars (\$000s)</u> | Rate 01 | Rate 10 | Rate M1 | Rate M2 | Total |
|------------|-----------------------------|---------|---------|---------|---------|---------|
| | | (a) | (b) | (c) | (d) | (e) |
| 1 | Delivery Revenue Balances | 3,594 | 2,444 | 4,539 | 5,779 | 16,355 |
| 2 | Storage Revenue Balances | 1,873 | 1,407 | 916 | 886 | 5,081 |
| 3 | Storage Cost Balances | (201) | (99) | (890) | (1,249) | (2,438) |
| 4 | Interest | 64 | 45 | 65 | 65 | 239 |
| 5 | Total NAC Deferral Balance | 5,330 | 3,797 | 4,629 | 5,481 | 19,237 |

3. Deferral Account Impacts

11. For Rate M1, the 2021 actual NAC is lower than the target NAC used to derive base rates by 108 m³/customer (Table 1, line 3, column (c)) and lower than the target NAC used to derive Y factor rates by 24 m³/customer (Table 2, line 3, column (c)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of \$5.454 million (\$4.539 million and \$0.916 million respectively). In addition, the NAC volume variance decreases the Rate M1 storage requirement by 1.310 PJ. Accordingly, EGI must refund an amount of \$0.890 million (Table 3, line 3, column (c)) to Rate M1 customers to recognize the decreased Rate M1 storage requirements.

12. For Rate M2, the 2021 actual NAC is lower than the target NAC used to derive base rates by 18,580 m³/customer (Table 1, line 3, column (d)) and lower than the target NAC used to derive Y factor rates by 19,637 m³/customer (Table 2, line 3, column (d)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of \$6.665 million (\$5.779 million and \$0.886 million

respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.840 PJ. Accordingly, EGI must refund \$1.249 million (Table 3, line 3, column (d)) to Rate M2 customers to recognize the decreased Rate M2 storage requirements.

13. For Rate 01, the 2021 actual NAC is lower than the target NAC used to derive base rates by 124 m³/customer (Table 1, line 3, column (a)) and lower than the target NAC used to derive Y factor rates by 64 m³/customer (Table 2, line 3, column (a)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of \$5.467 million (\$3.594 million and \$1.873 million respectively). In addition, the NAC volume variance decreased the Rate 01 storage requirement by 0.240 PJ. Accordingly, EGI must refund an amount of \$0.201 million (Table 3, line 3, column (a)) to Rate 01 customers to recognize the decreased Rate 01 storage requirements.

14. For Rate 10, the 2021 actual NAC is lower than the target used to derive base rates NAC by 20,129 m³/customer (Table 1, line 3, column (b)) and lower than the target NAC used to derive Y factor rates by 15,431 m³/customer (Table 2, line 3, column (b)). As shown in Table 3 above, this results in a delivery and storage revenue debit to ratepayers of \$3.851 million (\$2.444 million and \$1.407 million respectively). In addition, the NAC volume variance decreases the Rate 10 storage requirement by 0.120 PJ. Accordingly, EGI must refund \$0.099 million (Table 3, line 3, column (b)) to Rate 10 customers to recognize the decreased Rate 10 storage requirements.

4. Storage Costs

15. The storage costs recognize that variances between the 2021 target NAC and the 2013 OEB-approved NAC change the storage requirements for each general service rate class. As OEB-approved storage rates are not updated during the IR term to reflect changes in storage requirements due to NAC variances, EGI must capture

the NAC-related change in storage costs in the NAC Deferral Account for the Union rate zones as per the OEB's Decision in Union's 2013 Deferrals Disposition proceeding (EB-2014-0145), page. 9, "starting in 2014, the NAC Deferral Account, which replaces the Average Use Per Customer Deferral Account, will include storage related revenues and costs for general service rate classes."

16. To determine the change in storage requirements for each general service rate class due to NAC variances, the Company calculated the NAC volume variance per customer between its 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes multiplied by the 2013 OEB-approved number of customers.
17. Using the OEB-approved aggregate excess methodology, EGI calculated the change in storage requirements for each of the general service rate classes due to variances in NAC. The 2021/2022 Gas Supply Plan volumes represent the April 1, 2021 to March 31, 2022 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2021. These general service rate class storage requirements are then used in the calculation of the total in-franchise utility storage space requirement at November 1, 2021. The difference between the total in-franchise utility storage requirement and the total 100 PJ of utility storage represents the excess utility storage capacity available for sale (excess utility space) at November 1, 2021.
18. For Rate M1, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was a decrease of 6.254 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate M1 storage requirement by 1.310 PJ. This resulted in decreased storage costs of \$0.890 million (Table 3, line 3, column (c)).

19. For Rate M2, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 4.705 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.840 PJ and resulted in decreased storage costs of \$1.249 million (Table 3, line 3, column (d)).
20. For Rate 01, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 0.164 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate 01 storage requirement by 0.240 PJ and decreased storage costs by \$0.201 million (Table 3, line 3, column (a)).
21. For Rate 10, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes was an increase of 0.543 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate 10 storage requirement by 0.120 PJ and resulted in decreased storage costs of \$0.099 million (Table 3, line 3, column (b)).
22. Overall, the NAC volume variance between the 2021/2022 Gas Supply Plan and the 2013 OEB-approved volumes resulted in a decrease in general service storage requirements of 3.510 PJ. Accordingly, EGI has included a storage cost credit of \$2.438 million in the NAC Deferral Account. Please see Table 4 below for a summary of the change in general service storage requirements due to NAC volume variances by rate class.

Table 4
Change in General Service Storage Requirements from 2013
OEB-approved (based on weather normalized NAC)

| | PJ | | PJ |
|-------------|----------------|-------------|----------------|
| Rate M1 | (1.310) | Rate 01 | (0.240) |
| Rate M2 | (1.840) | Rate 10 | (0.120) |
| Total South | <u>(3.150)</u> | Total North | <u>(0.360)</u> |

23. The reduction in storage activity has decreased storage deliverability costs, the commodity-related costs at Dawn and storage inventory carrying costs.

24. The 3.510 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 2.984 PJ of excess utility space available for sale for winter 2021/2022. The revenue from the sale of the 2.984 PJ of excess utility space is recorded in the Short-Term Storage and Other Balancing Deferral Account (Account No. 179-70).

DEFERRAL CLEARING VARIANCE ACCOUNT– UNION RATE ZONES

1. The purpose of the Deferral Clearing Variance Account (DCVA) is to capture the differences between the forecast and actual volumes associated with the disposition of deferral account balances to the Union rate zones. The intent of the variance account is to minimize or eliminate the gains or losses to ratepayers and the Company as a result of volume variances associated with the disposition of deferral account balances.
2. The balance in this variance account is a credit to Union rate zones ratepayers of \$3.120 million, plus interest to December 31, 2022 of a \$0.046 million, for a total credit of \$3.166 million. The balance includes the following residual balances from various dispositions, discussed further below:

| | |
|---|---------------|
| a. Prospective Recovery Account Dispositions | (\$ millions) |
| i. 2017/18 Demand Side Management (DSM) | (1.990) |
| ii. 2019 Earnings Sharing and Deferrals | (1.982) |
| iii. 2019 Federal Carbon Pricing Program (FCPP) | (0.291) |
| b. One-time Adjustment Account Dispositions | |
| i. 2019 DSM | 1.122 |
3. As reflected in Exhibit E, Tab 1, Schedule 2, page 1, Line 5, the overall balance also reflects a debit of \$0.020 million in relation to the various deferral account dispositions including residual amounts not able to be disposed of as one-time billings and amounts related to manual rebills.

1. Prospective Recovery Account Dispositions

6. Of the account balance, a \$3.971 million credit balance, plus interest of \$0.589 credit, represents an under-refund/over-collection from ratepayers for dispositions disposed of using prospective recovery in the 2017/18 DSM Deferrals Disposition¹ and 2019 Earnings Sharing and Deferrals Disposition² proceedings. Please see Exhibit E, Tab 1, Schedule 5, page 1 for a summary of the deferral account balance disposed of using the prospective recovery method. Additionally, a \$0.291 million credit is a residual balance from the disposition of 2019 federal carbon balances in the 2020 FCPP³ proceeding.

1.1 Union Rate Zones 2017-2018 DSM Deferral (EB-2020-0067)

7. In its EB-2020-0067 Decision, the OEB approved the prospective disposition of the balances in the approved deferral accounts to rate classes through a temporary rate adjustment from April 1, 2021 to June 30, 2021. The total amount approved for prospective recovery from rate classes was a \$24.196 million debit. Please see Exhibit E, Tab 1, Schedule 5, page 2, column (f), for the forecast amount to be recovered by rate class, based on the forecasted volumes as noted in column (a) of the same exhibit.
8. Actual volumes for the period April 1, 2021 to June 30, 2021 averaged approximately 4% greater than forecast due to colder weather in the same period. As a result of the actual volumes being greater than the forecasted volumes, the Company recovered \$26.186 million, which is \$1.990 million more than the balance approved for disposition. Please see Exhibit E, Tab 1, Schedule 5, page 2, column (g) for the actual disposition of deferral accounts and column (h) of the same exhibit for the variance between forecast and actual disposition.

¹ EB-2020-0067.

² EB-2020-0134.

³ EB-2019-0247.

1.2 Union Rate Zones 2019 Earnings Sharing and Deferrals Disposition
(EB-2020-0134)

9. In its EB-2020-0134 Decision, the OEB approved the prospective disposition of the balances in the approved deferral accounts to rate classes through a temporary rate adjustment from October 1, 2021 to December 31, 2021. The total amount approved for prospective refund to rate classes was a \$14.096 million credit. Please see Exhibit E, Tab 1, Schedule 5, page 3, column (e), for the forecast amount to be refunded by rate class, based on the forecasted volumes as noted in column (a) of the same exhibit.
10. Actual volumes for the period October 1, 2021 to December 31, 2021 averaged approximately 19% lower than forecast primarily due to warmer weather in the same period. As a result of the actual volumes being lower than the forecasted volumes, the Company refunded \$12.115 million, which is \$1.982 million less than the balance approved for disposition. Please see Exhibit E, Tab 1, Schedule 5, page 3, column (f) for the actual disposition amounts by rate class, based on the actual volumes as shown in column (b). Column (g) of the same exhibit shows the variance between forecast and actual disposition.

1.3 Union Rate Zones 2020 Federal Carbon Pricing Program (EB-2019-0247)

5. A \$0.291 million credit balance pertains to over-collection from ratepayers related to the 2019 FCPP deferral and variance account disposition within the 2020 FCPP proceeding. In its EB-2019-0247 Decision, the OEB approved the prospective disposition of the balances in the 2019 FCPP deferral accounts to rate classes through a temporary rate adjustment from October 1, 2020 to December 31, 2020.
6. Following the OEB's approval of 2019 balances, contract customers were subsequently exempted from the customer-related federal carbon levy. Enbridge Gas had already received approval to collect amounts from Union rate zones

customers related to the exempted customers, therefore, the over-collection from customers requires a disposition to ratepayers.

2. One-time Adjustment Account Disposition

11. The 2019 DSM Deferrals Disposition was the first time Enbridge Gas used a common disposition methodology across the EGD and Union rate zones. The Rate Order of that proceeding reflects a one-time billing adjustment for all Enbridge Gas customers.

2.1 Union Rate Zones 2019 DSM Deferrals (EB-2021-0072)

12. A \$1.122 million debit balance represents an under-collection from ratepayers for disposition using one-time-adjustment in the 2019 DSM Deferrals Disposition⁴ proceeding. In July of 2021, the Company received approval to clear the 2019 DSM deferral accounts within the EB-2021-0072 proceeding and dispose of the balance in October 2021. The billing adjustment was derived for each customer individually by applying the disposition unit rates to each customer's actual consumption volume for the period July 1, 2019 to June 30, 2020 for the Union rate zone general service customers.⁵ The outstanding amount is as a result of the billing systems' inability to locate all the intended customers.

⁴ EB-2021-0072.

⁵ Enbridge Gas Draft Rate Order, EB-2021-0072, June 30, 2021.

PARKWAY WEST PROJECT COSTS DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Parkway West Project (EB-2012-0433) Decision, the OEB approved the establishment of the Parkway West Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Parkway West Project and the revenue requirement included in rates.
2. The balance in this deferral account is a credit to Union rate zones ratepayers of \$0.603 million plus interest of \$0.006 million for a total credit balance of \$0.609 million. The balance of \$0.603 million represents the difference between the revenue requirement of \$19.971 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$19.368 million as shown in Table 1.

TABLE 1
2021 PARKWAY WEST PROJECT RATE BASE AND REVENUE REQUIREMENT

| Line No. | Particulars (\$000's) | Col. 1 2021 Board-approved (a) | Col. 2 2021 Actuals (b) | Col. 3 Difference (c) = (b - a) |
|---|---|--------------------------------------|-------------------------------|---------------------------------------|
| <u>Rate Base Investment</u> | | | | |
| 1. | Capital Expenditures | - | 15 | 15 |
| 2. | Cumulative Capital Expenditures | 233,147 | 231,703 | (1,444) |
| 3. | Average Investment | 199,738 | 198,371 | (1,367) |
| <u>Revenue Requirement Calculation:</u> | | | | |
| <u>Operating Expenses:</u> | | | | |
| 4. | Operating and Maintenance Expenses | 2,206 | 1,871 | (335) |
| 5. | Depreciation Expense (1) | 5,532 | 5,496 | (36) |
| 6. | Property Taxes | 579 | 388 | (191) |
| 7. | Total Operating Expenses | 8,317 | 7,755 | (562) |
| 8. | Required Return (2) | 11,304 | 11,227 | (77) |
| 9. | Total Operating Expense and Return | 19,621 | 18,982 | (639) |
| <u>Income Taxes:</u> | | | | |
| 10. | Income Taxes - Equity Return (3) | 2,315 | 2,299 | (16) |
| 11. | Income Taxes - Utility Timing Differences (4) | (1,966) | (1,914) | 52 |
| 12. | Total Income Taxes | 350 | 385 | 35 |
| 13. | Total Revenue Requirement | 19,971 | 19,368 | (603) |

Notes:

- (1) Depreciation expense at 2013 Board-approved depreciation rates.
- (2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
 $\$198.326 \text{ million} \times 64\% \times 3.82\% = \$4.849 \text{ million plus}$
 $\$198.326 \text{ million} \times 36\% \times 8.93\% = \$6.376 \text{ million for a total of } \11.225 million.
- (3) Taxes related to the equity component of the return at a tax rate of 26.5%.
- (4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Capital Expenditures

3. The actual 2021 capital expenditures on in-service assets are \$0.015 million higher than 2021 OEB-approved as shown in Table 2.

TABLE 2
PARKWAY WEST CAPITAL EXPENDITURES

| Line No. | Particulars (\$000's) | 2021 Board-approved (a) | 2021 Actuals (b) | Difference (c) = (b - a) |
|----------|----------------------------|----------------------------|---------------------|-----------------------------|
| 1. | Plant Infrastructure | - | 15 | 15 |
| 2. | Compressor Equipment | - | - | - |
| 3. | Total Capital Expenditures | - | 15 | 15 |

4. Plant infrastructure costs were \$0.015 million higher than costs included in 2021 OEB-approved rates due to consulting fees regarding the heritage homes discussed in the Company's 2019 Earnings Sharing and Deferrals Disposition interrogatory response to OEB staff¹. Enbridge Gas plans to mothball the heritage homes in 2022.

2. Average Investment

5. The average investment decrease of \$1.367 million from OEB-approved is due to the cumulative capital expenditures being \$1.444 million lower than OEB-approved.

3. Operating Expenses

6. Operating and maintenance expenses were \$0.335 million below the costs included in the 2021 OEB-approved rates. The decrease is a result of a Long-term Service Agreement (LTSA) that was included in 2021 OEB-approved rates but not incurred in actual O&M expense. The Company elected not to enter an LTSA, that would

¹ EB-2020-0134, EGI 2019 Earnings Sharing and Deferrals Disposition, Exhibit I.STAFF.25, a).

have provided loss of critical unit coverage should the Company experience operational issues with Parkway B, as with the commissioning of Parkway D it was determined that it provided the required backup.

7. Property taxes were \$0.191 million lower than costs included in 2021 OEB-approved rates. The decrease is a result of the Municipal Property Assessment Corporation (MPAC) deciding not to apply a Land Classification tax charge that was expected for 2019 and onwards.

BRANTFORD KIRK WALL/PARKWAY D PROJECT COSTS
UNION RATE ZONES

1. In its Brantford-Kirkwall/Parkway D (EB-2013-0074) Decision, the OEB approved the establishment of the Brantford-Kirkwall/Parkway D Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Brantford-Kirkwall/Parkway D Project and the revenue requirement included in rates.
2. The balance in this deferral account is a credit to Union rate zone ratepayers of \$0.045 million plus interest of \$0.003 million for a total credit balance of \$0.045 million. The balance of \$0.045 million represents the difference between the revenue requirement of \$15.329 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$15.284 million as shown in Table 1. The small decline in the actual revenue requirement results from minor underages in the capital cost and municipal taxes of the project.

TABLE 1
2021 BRANTFORD-KIRK WALL PIPELINE/PARKWAY D PROJECT RATE BASE AND REVENUE REQUIREMENT

| | Col. 1 | Col. 2 | Col. 3 |
|----------|----------------------------|---------------------|-----------------------------|
| Line No. | 2021 Board-approved (a) | 2021 Actuals (b) | Difference (c) = (b - a) |
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Notes:

- (1) Depreciation expense at 2013 Board-approved depreciation rates.
- (2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
 $\$167.680 \text{ million} \times 64\% \times 3.82\% = \$4.099 \text{ million plus}$
 $\$167.680 \text{ million} \times 36\% \times 8.93\% = \$5.39 \text{ million for a total of } \9.490 million.
- (3) Taxes related to the equity component of the return at a tax rate of 26.5%.
- (4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

UNACCOUNTED FOR GAS VOLUME DEFERRAL ACCOUNT
UNION RATE ZONES

1. The purpose of the Unaccounted for Gas (UFG) Volume Deferral Account is to capture the difference between the unit cost of UFG recovered in the rates approved by the OEB and actual UFG costs incurred. The amount of the UFG volume deferral account to be cleared to customers is subject to a symmetrical dead-band of \$5.0 million, with amounts within such dead-band being to Enbridge Gas's account.
2. Union rate zones' 2021 Board Approved rates included \$10.1 million in UFG costs. Based on 2021 actual volumes, Enbridge Gas recovered \$10.4 million in UFG costs for 2021. In comparison, Enbridge Gas's actual 2021 UFG costs were \$35.9 million. The difference of \$25.5 million is above the \$5.0 million threshold established by the OEB for the UFG Volume Variance Account. As a result, there is a debit balance of \$20.5 million in the UFG Volume Deferral Account, plus interest of \$0.2 million for a total debit balance of \$20.7 million. See Table 1 below.

Table 1
2021 UTILITY UFG VARIANCES FROM BOARD-APPROVED

| Line No. | Particulars | Variance (\$Millions) |
|-------------|---|--------------------------|
| 1 | UFG Cost Included in Rates | \$ 10.1 |
| 2 | Net Recovery Variance | \$ 0.3 |
| 3 | Total UFG Collected in 2021 Rates (line 1 + line 2) | \$ 10.4 |
| 4 | Total Utility UFG Actual Cost | \$ 35.9 |
| 5 | Total Utility UFG Variance (line 3 - line 4) | -\$ 25.5 |
| 6 | \$5M UFG Symmetrical Dead-band | \$ 5.0 |
| 7 | UFG Volume Deferral (receivable) | -\$ 20.5 |

(1) Board Approved throughput was 32,010 10⁶m³ versus actual throughput of 37,612 10⁶m³

(2) Board Approved UFG % is 0.219% versus actual UFG % of 0.672% for 2021.

3. The methodology for determining the actual UFG expense of \$35.9 million in 2021 is consistent with the methodology historically used to calculate actual UFG for the audited Financial Statements, utility rate setting and earnings calculation.
4. Table 2 and Table 3 provide historical UFG volumes and percentage of throughput for the Union rate zone from 2001 to 2021.

Table 2: Historical UFG Percentage of Throughput for the Union Rate Zone

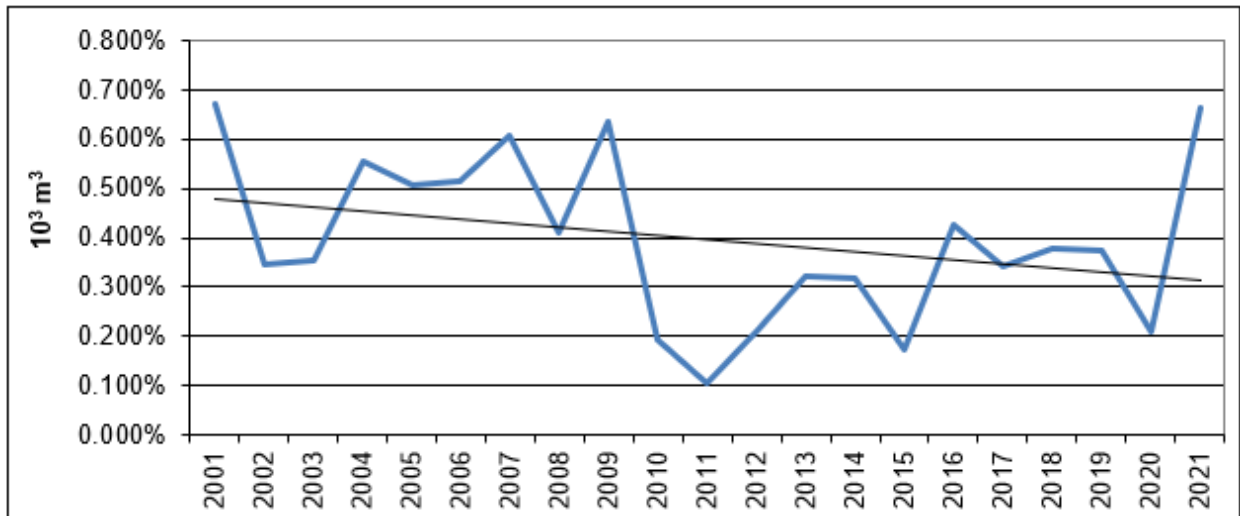


Table 3

| <i>Col.1</i> | <i>Col.2</i> | <i>Col.3</i> |
|----------------------|---|--------------|
| Calendar Year | UFG Volumes (10³ m³) | UFG % |
| 2001 | 184,102 | 0.673% |
| 2002 | 109,542 | 0.344% |
| 2003 | 108,819 | 0.356% |
| 2004 | 176,650 | 0.554% |
| 2005 | 169,540 | 0.507% |
| 2006 | 154,015 | 0.516% |
| 2007 | 203,713 | 0.609% |
| 2008 | 143,880 | 0.411% |
| 2009 | 201,845 | 0.637% |
| 2010 | 67,283 | 0.192% |
| 2011 | 35,668 | 0.105% |
| 2012 | 68,690 | 0.210% |
| 2013 | 113,997 | 0.320% |
| 2014 | 97,109 | 0.318% |
| 2015 | 54,408 | 0.174% |
| 2016 | 131,588 | 0.427% |
| 2017 | 108,901 | 0.342% |
| 2018 | 136,447 | 0.379% |
| 2019 | 137,652 | 0.376% |
| 2020 | 74,120 | 0.208% |
| 2021 | 252,582 | 0.672% |

5. The 0.219% UFG percentage used in approved rates was determined in EB-2011-0210 using the weighted average of the previous three years actual UFG. At the time 2013 rates were set, the most recent three years actual UFG available was 2009 to 2011. The Board approved methodology uses a 3:2:1 weighting with the most recent year weighted most heavily. The result was a ratio for UFG in rates influenced heavily by 2011's favourable ratio. Concern over the ability to manage UFG relative to the new ratio was a factor in the establishment of a deferral account to capture variances, as was approved in EB-2013-0202.

6. Since the 2013 Board Approved percentage was determined, the average UFG percentage has been 0.356%, for the years of 2013 through 2021. Within that period of 2013 through 2021, the UFG % in 2015 was notably lower than the average, with a corresponding increase in 2016. Similarly, the UFG % in 2020 was lower than the average, with an increase in the UFG % observed in 2021.
7. As was noted in EB-2017-0091 Exhibit B.Staff.9, the increase in UFG volumes experienced in 2016 was primarily driven by a decrease in delivery volumes recorded in January 2016 relating to true-up of estimated consumption recorded in December 2015.
8. A similar decrease and offsetting increase in UFG volumes has been observed between the 2020 and 2021 calendar years. The average UFG % for 2020 and 2021 is 0.440%, which is approximately $163.5 \text{ } 10^3\text{m}^3/\text{year}$ average for the two years. The Company has identified that the true-up of estimated consumption based on the calendarization of UFG volumes has contributed to volatility between 2020 and 2021, but has not resulted in a material increase to the historical average of UFG over the course of two years. Typical estimation true-ups are outlined below.
9. At the end of each reporting period, Enbridge Gas records an estimate of gas delivered but not yet billed. The true-up between the December 2020 estimate and the actual billed volumes resulted in a decrease to the delivery volumes recorded in January 2021. This true-up reflects that, when billings related to December 2020 were completed over the following month, it was determined there was an over-estimate of gas deliveries for December 2020.
10. A second common estimation true-up is known as a prior period adjustment (PPA). PPAs are processed when there is a variance between a billed estimate and actual volumes. The inclusion of PPAs within the annual reported consumption volumes is

consistent with the methodology historically used to calculate actual UFG for the audited Financial Statements, utility rate setting and earnings sharing calculation.

11. The UFG volumes in 2020 were abnormally low compared to the historical average.

The estimation true-up recorded in 2021 caused UFG volumes in 2021 to be elevated. As mentioned, the average of 2020 and 2021 is in line with the historical average of UFG volumes from 2013 to 2021.

12. Enbridge evaluated other factors that could have impacted UFG including, investigating meter reads between custody and check meters for inconsistencies, reviewing accounting processes associated with recording company use and line-pack changes, assessing impacts arising from the transition of Union rate zone customers to the SAP customer information system, and reviewing storage inventory adjustments. These items were deemed to have minimal impact on the elevated level of UFG in 2021. Enbridge is continuing to monitor and address potential contributors to UFG.

13. Volatility in UFG is not uncommon and is experienced across the gas utility industry. The 2019 UFG report prepared by ScottMadden filed in the 2020 Rates Application (EB-2019-0194) noted that:

“....legacy Union and legacy EGD have year-to-year fluctuations in UFG levels that are generally consistent with those of other gas utilities. The fluctuations are a result of many factors, including weather, estimation variation, measurement variation, and billing and accounting adjustments.all gas distribution pipeline systems have UFG as an element of operating a natural gas distribution system and that because of the numerous factors that impact UFG, the UFG percentage will fluctuate over time.¹”

¹ EB-2019-0194, UFG Progress Report, page 4.

14. Enbridge Gas filed the 2019 UFG Study as part of the 2020 rate application (EB-2019-0194). The report found that the primary sources of UFG include physical losses (eg. leaks, third-party damage and venting), metering variations, non-registering meters, theft, line pack and billing and accounting adjustments (such as the estimate of gas delivered but not yet billed required at the end of each reporting period to report results). Although the root causes of UFG are generally known as described above, it continues to be difficult to quantify the individual factors due to their nature. Certain sources of UFG, such as leaks and emissions, contribute to baseline UFG while other sources such as billing, and accounting adjustments contribute to UFG volatility.
15. As committed by the Company in 2020 Rates application (EB 2019-0194), Enbridge Gas will file an update in the 2024 rebasing application about the implementation of the UFG report recommendations and other activities to address UFG, and the impacts of such activities.

UNACCOUNTED FOR GAS (UFG) PRICE VARIANCE ACCOUNT
UNION RATE ZONES

1. The UFG Price Variance Account captures the variance between the average monthly price of the Company's purchases for the Union rate zones and the applicable OEB-approved reference price, applied to the Company's actual UFG volumes for the Union rate zones. During 2021, the Company purchased 63,961 10^3m^3 of gas supply in Union rate zones related to actual UFG volumes on behalf of ratepayers. The actual UFG purchases exclude the actual UFG collected from ratepayers who provide UFG in kind as part of customer supplied fuel (CSF).
2. The average actual cost of the UFG purchases in 2021 is $\$52.52/10^3\text{m}^3$ higher than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of $\$141.35/10^3\text{m}^3$. The result is a $\$3.36$ million balance to be collected from ratepayers, as shown in Table 1 below. Table 2 provides the detailed calculation supporting the price variance of $\$52.52/10^3\text{m}^3$.

Table 1
Calculation of 2021 UFG Price Variance

| Line No. | | UFG Volumes (10 ³ m ³) |
|----------|---|--|
| 1 | Experienced UFG ⁽¹⁾ | 270,030 |
| 2 | UFG Collected through CSF | 206,069 |
| 3 | UFG Volumes – Company Supplied ⁽²⁾ | <u>63,961</u> |
| | | <u>Deferral Calculation</u> |
| 4 | UFG Volumes (10 ³ m ³) – Company Supplied ⁽²⁾ | 63,961 |
| 5 | Price Variance (\$/10 ³ m ³) ⁽³⁾ | <u>\$52.52</u> |
| 6 | Variance Account Balance (\$ millions) | <u>\$3.36</u> |

(1) Converted using the following heat values (39.28 Jan-Mar) (39.32 Apr – Dec).

(2) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.

(3) See Table 2 for the price variance calculation. This represents weighted average actual cost relative to OEB-approved reference prices.

Table 2
Calculation of 2021 Union South Price Variance

| Line No. | Union South Rate Zone | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Average Price |
|----------|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|---------------|
| 1.0 | Board Approved Reference Price (\$ / 10 ³ m ³) | \$ 131.43 | \$ 131.43 | \$ 131.43 | \$ 135.62 | \$ 135.62 | \$ 135.62 | \$ 129.13 | \$ 129.13 | \$ 129.13 | \$ 169.23 | \$ 169.23 | \$ 169.23 | \$ 141.35 |
| 2.0 | Actual Purchase (\$) | \$42,507,900 | \$45,125,048 | \$43,018,711 | \$32,580,518 | \$38,260,250 | \$36,250,196 | \$51,360,970 | \$55,362,122 | \$58,149,557 | \$60,445,476 | \$92,591,845 | \$92,645,865 | |
| 3.0 | Purchase Volumes (10 ³ m ³) | 325,958 | 294,013 | 281,053 | 249,025 | 268,780 | 268,626 | 286,082 | 274,130 | 267,494 | 208,408 | 307,429 | 318,118 | |
| 4.0 | Average Purchase Cost (Union South) (\$ / 10 ³ m ³) | \$ 130.41 | \$ 153.48 | \$ 153.06 | \$ 130.83 | \$ 142.35 | \$ 134.95 | \$ 179.53 | \$ 201.96 | \$ 217.39 | \$ 290.03 | \$ 301.18 | \$ 291.23 | \$ 193.87 |
| 5.0 | Union South Price Variance (\$ / 10 ³ m ³) ⁽¹⁾ | \$ 1.02 | \$ (22.05) | \$ (21.63) | \$ 4.78 | \$ (6.73) | \$ 0.67 | \$ (50.41) | \$ (72.83) | \$ (88.26) | \$ (120.80) | \$ (131.95) | \$ (122.00) | \$ (52.52) |

Notes
(1) Line 1 - Line 4

LOBO C COMPRESSOR/HAMILTON MILTON PIPELINE PROJECT COSTS
DEFERRAL ACCOUNT – UNION RATE ZONES

1. In its Dawn Parkway 2016 Expansion (EB-2014-0261) Decision, the OEB approved the establishment of the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Project and the revenue requirement included in rates.
2. The balance in this deferral account is a debit from Union Rate Zone ratepayers of \$0.024 million plus interest of \$0.0003 million for a total debit balance of \$0.024 million. The balance of \$0.024 million represents the difference between the revenue requirement of \$26.025 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$26.049 million as shown in Table 1.

TABLE 1
2021 LOBO C COMPRESSOR/HAMILTON-MILTON PIPELINE PROJECT RATE BASE AND REVENUE REQUIREMENT

| Line No. | Particulars (\$000's) | Col. 1 | Col. 2 | Col. 3 |
|----------|---|----------------------------|---------------------|-----------------------------|
| | | 2021 Board-approved (a) | 2021 Actuals (b) | Difference (c) = (b - a) |
| | <u>Rate Base Investment</u> | | | |
| 1. | Capital Expenditures | - | - | - |
| 2. | Cumulative Capital Expenditures | 347,980 | 347,062 | (918) |
| 3. | Average Investment | 306,868 | 306,005 | (863) |
| | <u>Revenue Requirement Calculation:</u> | | | |
| | <u>Operating Expenses:</u> | | | |
| 4. | Operating and Maintenance Expenses | 863 | 1,104 | 241 |
| 5. | Depreciation Expense (1) | 8,261 | 8,214 | (47) |
| 6. | Property Taxes | 1,210 | 1,056 | (154) |
| 7. | Total Operating Expenses | 10,334 | 10,374 | 40 |
| 8. | Required Return (2) | 16,464 | 16,417 | (47) |
| 9. | Total Operating Expense and Return | 26,798 | 26,791 | (7) |
| | <u>Income Taxes:</u> | | | |
| 10. | Income Taxes - Equity Return (3) | 3,562 | 3,547 | (15) |
| 11. | Income Taxes - Utility Timing Differences (4) | (4,335) | (4,289) | 46 |
| 12. | Total Income Taxes | (773) | (742) | 31 |
| 13. | Total Revenue Requirement | 26,025 | 26,049 | 24 |

Notes:

- (1) Depreciation expense at 2013 Board-approved depreciation rates.
- (2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
 $\$306.868 \text{ million} \times 64\% \times 3.36\% = \$6.599 \text{ million plus}$
 $\$306.868 \text{ million} \times 36\% \times 8.93\% = \$9.865 \text{ million for a total of } \$16,464 \text{ million.}$
- (3) Taxes related to the equity component of the return at a tax rate of 26.5%.
- (4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

3. The average investment decrease of \$0.863 million from OEB-approved is due to the cumulative capital expenditures being \$0.918 million lower than OEB-approved capital expenditures.

2. Operating Expenses

4. Operating and maintenance expenses were \$0.241 million higher than the costs included in 2021 OEB-approved rates. The increase is a result of higher salaries/wages related to overtime costs not included in the original budget and pertain to the annual operations and general maintenance of the equipment and assets.

3. Property Tax

5. Property taxes were \$0.154 million lower than costs included in 2021 OEB-approved rates. The decrease is a result of Provincial tax reductions for business education tax rates on commercial, industrial, and pipeline tax in 2021.

LOBO D/BRIGHT C/DAWN H COMPRESSOR PROJECT COSTS
UNION RATE ZONES

1. In its EB-2015-0116 Decision, the OEB approved the establishment of the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Lobo D/Bright C/Dawn H Compressor Project and the revenue requirement included in rates.
2. The balance in this deferral account is a credit to Union Rate Zone ratepayers of \$0.112 million plus interest of \$0.004 million, for a total credit balance of \$0.116 million. The balance of \$0.116 million includes a debit of \$1.225 million which represents the difference between the revenue requirement of \$45.154 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$46.379 million as shown in Table 1.
3. A \$1.337 million credit relates to the 2021 revenue generated from the sale of surplus Dawn Parkway system capacity of 30,393 GJ/day associated with the Lobo D/Bright C/Dawn H Compressor Project. In accordance with the 2018 Disposition of Deferral and Variance Account Balances and Utility Earnings proceeding (EB-2019-0105) approved Settlement Proposal, the surplus capacity is deemed to be sold long-term and the revenue credit for the 2021 year is calculated based on the M12 Dawn-Parkway rate of \$3.665/GJ approved in the EB-2020-0181 Rate Order, dated May 18, 2021. A schedule supporting the 2021 revenue calculation is provided at Exhibit E, Tab 1, Schedule 7.

TABLE 1

2021 DAWN H/LOBO D/BRIGHT C COMPRESSOR PROJECT RATE BASE AND REVENUE REQUIREMENT

| Line No. | Particulars (\$000's) | Col. 1 | Col. 2 | Col. 3 |
|----------|---|----------------------------|---------------------|-----------------------------|
| | | 2021 Board-approved (a) | 2021 Actuals (b) | Difference (c) = (b - a) |
| | <u>Rate Base Investment</u> | | | |
| 1. | Capital Expenditures | - | - | - |
| 2. | Cumulative Capital Expenditures | 622,500 | 620,050 | (2,450) |
| 3. | Average Investment | 552,367 | 551,923 | (444) |
| | <u>Revenue Requirement Calculation:</u> | | | |
| | <u>Operating Expenses:</u> | | | |
| 4. | Operating and Maintenance Expenses | 1,761 | 2,675 | 914 |
| 5. | Depreciation Expense (1) | 17,418 | 17,437 | 19 |
| 6. | Property Taxes | 1,089 | 1,031 | (58) |
| 7. | Total Operating Expenses | 20,268 | 21,143 | 875 |
| 8. | Required Return (2) | 29,388 | 29,364 | (24) |
| 9. | Total Operating Expense and Return | 49,656 | 50,507 | 851 |
| | <u>Income Taxes:</u> | | | |
| 10. | Income Taxes - Equity Return (3) | 6,402 | 6,397 | (5) |
| 11. | Income Taxes - Utility Timing Differences (4) | (10,905) | (10,526) | 379 |
| 12. | Total Income Taxes | (4,503) | (4,129) | 374 |
| 13. | Total Revenue Requirement | 45,154 | 46,379 | 1,225 |

Notes:

- (1) Depreciation expense at 2013 Board-approved depreciation rates.
- (2) The required return assumes a capital structure of 64% long-term debt at 3.29% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
 $\$552.367 \text{ million} \times 64\% \times 3.29\% = \$11.631 \text{ million plus}$
 $\$552.367 \text{ million} \times 36\% \times 8.93\% = \$17.757 \text{ million for a total of } \29.388 million.
- (3) Taxes related to the equity component of the return at a tax rate of 26.5%.
- (4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

4. The average investment decrease of \$0.444 million from OEB-approved is due to the cumulative capital expenditures being \$2.450 million lower than OEB-approved.

2. Operating Expenses

5. Operating and maintenance expenses were \$0.914 million higher than the costs included in 2021 OEB-approved rates. The increase is a result of higher salaries/wages as the budget did not account for overtime costs, higher general maintenance costs than budgeted, and higher utility costs than budgeted. Salary/wages costs were not capitalized or captured in contingency costs as they were incurred for the annual operations and general maintenance of the equipment and assets. Table 2 shows the breakdown and comparison of actual 2021 operating and maintenance costs versus OEB-approved.

TABLE 2
2021 DAWN H/LOBO D/BRIGHT C COMPRESSOR OPERATING AND MAINTENANCE
EXPENSES

| Line No. | Particulars (\$Millions) | Col. 1 | Col. 2 | Col. 3 |
|-------------|-------------------------------|--------------------------------|------------------------|-----------------------------|
| | | 2021 Board- approved (a) | 2021 Actuals (b) | Difference (c) = (b - a) |
| 1. | Salaries & Wages | 870 | 1,285 | 415 |
| 2. | HR Costs | 392 | 576 | 184 |
| 3. | Fleet Costs | 131 | 193 | 62 |
| 4. | Training, Travel and PE | 67 | 12 | (55) |
| 5. | Other O&M (Contract Services) | 165 | 307 | 142 |
| 6. | Company Used Fuel | 73 | - | (73) |
| 7. | Utility Costs | 63 | 302 | 239 |
| 8. | Total Capital Expenditures | 1,761 | 2,675 | 914 |

3. Income Taxes

6. The \$0.379 million decrease in "Income Taxes – Utility Timing Difference" credit relates to a lower Capital Cost Allowance (CCA) deduction due to the lower average investment in 2021, versus OEB-approved, as well as lower CCA available on additions that were previously qualified for Bill C-97 accelerated CCA.

BURLINGTON OAKVILLE PROJECT COSTS DEFERRAL ACCOUNT

UNION RATE ZONES

1. In its EB-2015-0116 Decision, the OEB approved the establishment of the Burlington Oakville Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Project and the revenue requirement included in rates.
2. The balance in this deferral account is a credit to Union rate zone ratepayers of \$0.051 million plus interest of \$0.0004 million for a total credit balance of \$0.051 million. The balance of \$0.051 million represents the difference between the revenue requirement of \$5.707 million included in 2021 rates (EB-2020-0095) and the calculation of the actual revenue requirement for 2021 of \$5.656 million as shown in Table 1. The small decline in the actual revenue requirement results from minor underages in the capital cost and operating costs of the project.

TABLE 1
2021 BURLINGTON OAKVILLE PIPELINE PROJECT RATE BASE AND REVENUE REQUIREMENT

| Line No. | Particulars (\$000's) | Col. 1 2021 Board- approved (a) | Col. 2 2021 Actuals (b) | Col. 3 Difference (c) = (b - a) |
|----------|---|--|----------------------------------|---------------------------------------|
| | <u>Rate Base Investment</u> | | | |
| 1. | Capital Expenditures | - | - | - |
| 2. | Cumulative Capital Expenditures | 83,349 | 83,262 | (87) |
| 3. | Average Investment | 74,814 | 74,725 | (89) |
| | <u>Revenue Requirement Calculation:</u> | | | |
| | <u>Operating Expenses:</u> | | | |
| 4. | Operating and Maintenance Expenses | 17 | - | (17) |
| 5. | Depreciation Expense (1) | 1,732 | 1,737 | 5 |
| 6. | Property Taxes | 134 | 116 | (18) |
| 7. | Total Operating Expenses | 1,883 | 1,853 | (30) |
| 8. | Required Return (2) | 4,014 | 4,009 | (5) |
| 9. | Total Operating Expense and Return | 5,897 | 5,862 | (35) |
| | <u>Income Taxes:</u> | | | |
| 10. | Income Taxes - Equity Return (3) | 868 | 866 | (2) |
| 11. | Income Taxes - Utility Timing Differences (4) | (1,058) | (1,072) | (14) |
| 12. | Total Income Taxes | (190) | (206) | (16) |
| 13. | Total Revenue Requirement | 5,707 | 5,656 | (51) |

Notes:

- (1) Depreciation expense at 2013 Board-approved depreciation rates.
- (2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
 $\$74.814 \text{ million} \times 64\% \times 3.36\% = \$1.609 \text{ million plus}$
 $\$74.814 \text{ million} \times 36\% \times 8.93\% = \$2.405 \text{ million for a total of } \4.014 million.
- (3) Taxes related to the equity component of the return at a tax rate of 26.5%.
- (4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

2021 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT
UNION RATE ZONES

1. The purpose of the 2021 Ontario Energy Board Cost Assessment Variance Account (OEBCAVA) was to record any variances between the OEB costs assessed to Enbridge Gas (relevant to the Union rate zones) through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the OEB costs which were included in Union rate zones rates, which were determined through application of the prior CAM. The scope of the account is consistent with prior OEBCAVAs. However, in accordance with the EB-2020-0134 OEB-approved Settlement Proposal, in Enbridge Gas's 2019 Earnings Sharing and Deferral Disposition proceeding, the base OEB costs assumed to be included in rates have been escalated to reflect the growth in the amount recovered through rates, which results from annual price cap adjustments and customer growth. The OEBCAVA was originally approved for establishment by OEB letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model*.
2. The amount recorded within the 2021 OEBCAVA is a \$0.907 million debit plus interest of \$0.011 million for a total debit balance of \$0.919 million. This amount reflects the variance between OEB costs assessed to Enbridge Gas (relevant to Union rate zones) in each quarter of fiscal 2021, utilizing the revised CAM, and Union's average quarterly OEB cost assessment under the prior CAM, escalated in accordance with the EB-2020-0134 OEB-approved Settlement Proposal.
3. In order to calculate the amount to be recovered through the 2021 Union rate zones OEBCAVA, the Company first needed to apportion the actual 2021 OEB assessed costs between the legacy rate zones. Commencing with the OEB's 2019/2020 fiscal

first quarter assessment (for the period April 1, 2019 through June 30, 2019), and continuing since, EGI has been receiving one consolidated quarterly bill for the amalgamated utility. To apportion the quarterly assessments received in 2021 between rate zones, the assessments were prorated based on the total invoices received by each legacy utility for the OEB's 2018/2019 fiscal year (for the period April 1, 2018 through March 31, 2019), the final year for which the OEB issued invoices to each legacy utility. Table 1 below shows the proration of the OEB's 2018/2019 fiscal year assessments between each legacy utility/rate zone (59.76% EGD rate zone, 40.24% Union rate zones). Table 2 shows the apportionment of EGI's 2021 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2021 Union rate zones OEBCAVA.

4. To calculate the amount for recovery through the 2021 Union rate zones OEBCAVA, the Company also needed to establish the base comparator, reflecting the OEB costs included in Union rate zones rates, determined through application of the prior Cost Assessment Model. In accordance with the EB-2020-0134 OEB approved Settlement Proposal, the amount reflected in rates is also to be increased, or escalated, to reflect the growth in the amount recovered as a result of annual price cap adjustments and customer growth. To establish the 2021 base comparator, the Company escalated the 2020 quarterly comparator of \$0.718 million by the sum of the 2021 Price Cap Index (PCI) of 1.70%, and the Union rate zones ICM threshold calculation Growth Factor (g) of 1.46%, which were approved as part of EGI's 2021 Rate Application, EB-2020-0181. The escalation resulted in a 2021 quarterly comparator of \$0.741 million ($\$0.718 \text{ million} * (1 + (1.70\% + 1.46\%))$). As noted above, Table 2 below shows the apportionment of EGI's actual 2021 assessed costs to the Union rate zones, and the calculation of the amount recorded in the 2021 Union rate zones OEBCAVA utilizing a base comparator of \$0.741 million.

5. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2021 OEBCAVA, in the amount of \$0.907 million and \$0.011 million respectively, as shown in Exhibit C, Tab 1, Schedule 1.

Table 1

OEB 2018/2019 Cost Assessments

| | <u>EGD</u> | <u>UGL</u> | <u>Total</u> |
|-------------------------|---------------------|---------------------|---------------------|
| Apr. 1 to Jun. 30, 2018 | 1,467,963.00 | 988,479.00 | 2,456,442.00 |
| Jul. 1 to Sep. 30, 2018 | 1,356,860.00 | 913,873.00 | 2,270,733.00 |
| Oct. 1 to Dec. 31, 2018 | 1,356,860.00 | 913,873.00 | 2,270,733.00 |
| Jan. 1 to Mar. 31, 2019 | 1,356,860.00 | 913,873.00 | 2,270,733.00 |
| | <u>5,538,543.00</u> | <u>3,730,098.00</u> | <u>9,268,641.00</u> |
| Percentage of Total | 59.76% | 40.24% | 100.00% |

Table 2

Calculation of 2021 UGL RZ OEBCAVA

| <u>Period</u> | <u>EGI Assessment</u> | <u>UGL Rate Zones Share (40.24%)</u> | <u>Average cost assessment Comparator</u> | <u>Variance to UGL Rate Zone OEBCAVA</u> |
|-------------------------|-----------------------|--------------------------------------|---|--|
| Jan. 1 to Mar. 31, 2021 | 2,497,219.00 | 1,004,987.85 | 741,052.94 | 263,934.91 |
| Apr. 1 to Jun. 30, 2021 | 2,364,191.00 | 951,451.69 | 741,052.94 | 210,398.75 |
| Jul 1 to Sep. 30, 2021 | 2,379,076.00 | 957,442.05 | 741,052.94 | 216,389.11 |
| Oct. 1 to Dec. 31, 2021 | 2,379,076.00 | 957,442.05 | 741,052.94 | 216,389.11 |
| | | | | <u>907,111.89</u> |

2021 BASE SERVICE NORTH T-SERVICE TRANSCANADA CAPACITY DEFERRAL
ACCOUNT – UNION RATE ZONE

1. In the EB-2015-0181 decision, the OEB approved a new optional Union North T-service Transportation from Dawn to allow T-service customers in the Union North East Zone with access to Dawn-based supply. To facilitate this service, Enbridge Gas was required to contract for 15-year transportation capacity with TransCanada from Parkway to the Union CDA, Union NCDA and Union EDA. The approved rates for the service are equal to the EGI C1 rate from Dawn to Parkway and the TransCanada Firm Transportation (FT) toll to Delivery Area.
2. The purpose of the North T-service TransCanada Capacity Deferral Account is to record the difference between the costs for the capacity from Parkway to the northern Delivery Area as part of the Base Service offering of the North T-Service Transportation from Dawn and the demand revenues collected from the North T-Service customers.
3. The total cost Enbridge Gas paid for the contracted TransCanada capacity in 2021 was \$2.172 million or \$180,961.81 per month. On an actual basis, the Company collected \$2.088 million demand revenues from the North T-service customers. As a result, the balance of the 2021 North T-service TransCanada Capacity Deferral Account is a collection from ratepayers of \$0.084 million plus interest of \$0.0001 million and the balance will be cleared amongst all North T-service from Dawn customers. The variance is driven by a net reduction of 313 GJ/day of contracted capacity by North T-service customers.

PANHANDLE REINFORCEMENT PROJECT COSTS DEFERRAL ACCOUNT
UNION RATE ZONES

1. In its Panhandle Reinforcement Project (EB-2016-0186) Decision, the OEB approved the establishment of the Panhandle Reinforcement Project Costs Deferral Account to track the differences between the actual net revenue requirement related to costs for the Project and the net revenue requirement included in rates.
2. The balance in this deferral account is a credit to Union rate zone ratepayers of \$3.162 million plus interest of \$0.021 million for a total credit balance of \$3.183 million. The balance of \$3.162 million represents the difference between the net revenue requirement of \$10.701 million included in 2021 rates (EB-2020-0095) and the calculation of the actual net revenue requirement for 2021 of \$7.539 million as shown in Table 1.

TABLE 1
2021 PANHANDLE REINFORCEMENT PROJECT RATE BASE AND REVENUE REQUIREMENT

| Line No. | Particulars (\$000's) | Col. 1 | Col. 2 | Col. 3 |
|----------|---|----------------------------|---------------------|-----------------------------|
| | | 2021 Board-approved (a) | 2021 Actuals (b) | Difference (c) = (b - a) |
| | <u>Rate Base Investment</u> | | | |
| 1. | Capital Expenditures | - | - | - |
| 2. | Cumulative Capital Expenditures | 232,844 | 228,574 | (4,270) |
| 3. | Average Investment | 213,957 | 209,844 | (4,113) |
| | <u>Revenue Requirement Calculation:</u> | | | |
| | <u>Operating Expenses:</u> | | | |
| 4. | Operating and Maintenance Expenses | 16 | - | (16) |
| 5. | Depreciation Expense (1) | 4,944 | 4,921 | (23) |
| 6. | Property Taxes | 1,812 | 1,590 | (222) |
| 7. | Total Operating Expenses | 6,773 | 6,511 | (262) |
| 8. | Required Return (2) | 11,383 | 11,165 | (218) |
| 9. | Total Operating Expense and Return | 18,156 | 17,676 | (480) |
| | <u>Income Taxes:</u> | | | |
| 10. | Income Taxes - Equity Return (3) | 2,480 | 2,432 | (48) |
| 11. | Income Taxes - Utility Timing Differences (4) | (3,691) | (3,693) | (2) |
| 12. | Total Income Taxes | (1,211) | (1,261) | (50) |
| 13. | Total Revenue Requirement | 16,945 | 16,415 | (530) |
| 14. | Incremental Project Revenue | 6,243 | 8,876 | 2,633 |
| 15. | Net Revenue Requirement | 10,701 | 7,539 | (3,162) |

Notes:

- (1) Depreciation expense at 2013 Board-approved depreciation rates.
- (2) common equity at the 2013 Board-approved return of 8.93%. The 2021 required return calculation is as follows:
 $\$213.957 \text{ million} \times 64\% \times 3.29\% = \$4.505 \text{ million plus}$
 $\$213.957 \text{ million} \times 36\% \times 8.93\% = \$6.878 \text{ million for a total of } \11.383 million.
- (3) Taxes related to the equity component of the return at a tax rate of 26.5%.
- (4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

1. Average Investment

3. The average investment decrease of \$4.113 million from OEB-approved is due to the cumulative capital expenditures being \$4.270 million lower than OEB-approved.

2. Property Tax

4. Property taxes were \$0.222 million lower than costs included in 2021 OEB-approved rates. The decrease is a result of Provincial tax reductions for business education tax rates on commercial, industrial, and pipeline tax in 2021.

3. Required Return

5. The decrease in the required return of \$0.218 million is the result of a decrease in the average rate base.

4. Incremental Project Revenue

6. The actual incremental revenue of \$8.876 million reflects the continued addition of new customers and expansion by existing customers in the Panhandle market, primarily in the greenhouse sector and is \$2.633 million higher than the forecast incremental revenue included in 2021 Rates.

2021 PENSION AND OPEB FORECAST ACCRUAL VS ACTUAL CASH PAYMENT
DIFFERENTIAL VARIANCE ACCOUNT – UNION RATE ZONES

1. In its EB-2015-0040 report to all regulated entities, dated September 14, 2017, titled *“Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs”*, the OEB ordered the establishment of the deferral account, effective January 1, 2018, to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis¹. The Company recovers its pension and OPEB costs on an accrual basis.
2. The purpose of the Pension and OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account is to track the differences between forecast accrual pension and OPEB amounts recovered in rates, and the actual cash payments made for both pension and OPEB, on a go-forward basis from the date the account was established.
3. In 2021, the accrual pension and OPEB amount recovered in rates for the Union rate zones was \$47.4 million and the actual cash payments made for both pension and OPEB were \$22.6 million, resulting in an annual \$24.8 million credit variance. The variance carried forward from 2020 is a \$50.4 million credit variance, resulting in a cumulative \$75.2 million credit variance through 2021.
4. In accordance with the OEB’s Report (EB-2015-0040), when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, an asymmetrical carrying charge, to be returned to ratepayers, should be accrued based on the opening monthly difference between amount recovered in

¹ EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits (“OPEB”) Costs*, September 14, 2017, page 2.

rates and actual cash payments. The balance in the account for 2021 is an interest credit to ratepayers of \$1.346 million to December 31, 2021². Table 1 sets out the detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

TABLE 1

DETAILS OF 2021 INTEREST CALCULATED ON FORECAST ACCRUALS VS ACTUAL CASH PAYMENTS
IN PENSION AND OPEB VARIANCE ACCOUNT (NO. 179-157)

| Particulars (\$000's) | 20-Dec | 21-Jan | 21-Feb | 21-Mar | 21-Apr | 21-May | 21-Jun | 21-Jul | 21-Aug | 21-Sep | 21-Oct | 21-Nov | 21-Dec | Total |
|--------------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| Forecast accrual amounts | | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 3,951 | 47,416 |
| Actual cash payments | | 4,351 | 506 | 982 | 5,796 | 181 | 937 | 3,133 | 155 | 997 | 4,138 | 43 | 1,394 | 22,614 |
| Monthly variance | | 400 | -3,445 | -2,970 | 1,845 | -3,770 | -3,015 | -818 | -3,797 | -2,954 | 187 | -3,908 | -2,557 | -24,803 |
| Cumulative variance | -50,367 | -49,967 | -53,412 | -56,382 | -54,537 | -58,307 | -61,322 | -62,140 | -65,936 | -68,891 | -68,704 | -72,612 | -75,169 | |
| OEB prescribed CWIP rate | | 2.03 | 2.03 | 2.03 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | |
| Asymmetrical interest | | -87 | -78 | -92 | -106 | -109 | -111 | -117 | -119 | -126 | -131 | -131 | -139 | -1,346 |

² Interest is as of December 31, 2021, as interest on this account is calculated on a cumulative account balance basis.

ACCOUNTS WITH A ZERO BALANCE
UNION RATE ZONES

1. The following 2021 accounts for the Union rate zones have no balance, and are therefore not requested for clearance to customers:

- Spot Gas Variance Account
- Unbundled Services Unauthorized Storage Overrun Deferral Account
- Gas Distribution Access Rule (GDAR) Costs Deferral Account
- Conservation Demand Management Deferral Account
- Sudbury Replacement Project Costs Deferral Account
- Parkway Obligation Rate Variance Deferral Account
- Unauthorized Overrun Non-Compliance Account

TRANSPORTATION OPTIMIZATION DEFERRAL ACCOUNT - UNION RATE ZONES

| Line No. | Particulars | Col. 1 | Col. 2 | Col. 3 |
|-------------|--|-------------------------------------|-----------------------------------|-----------------------------------|
| | | 2013 Board Approved (\$000's) | 2020 Actual Total (\$000's) | 2021 Actual Total (\$000's) |
| 1. | Base Exchange Revenue | (9,118.00) | (4,243.99) | (7,528.52) |
| 2. | FT RAM Exchange Revenue | (5,800.00) | | |
| 3. | Total Exchange Revenue | (14,918.00) | (4,243.99) | (7,528.52) |
| 4. | Exchange Revenue Subject to Deferral | | (4,243.99) | (7,528.52) |
| 5. | Ratepayer portion - 90% | (13,426.20) | (3,819.59) | (6,775.67) |
| 6. | 10% Union Incentive Payment | | (424.40) | (752.85) |
| 7. | Less: Gas Supply Optimization Margin in Rates | 13,426.00 | 15,943.18 | 15,391.98 |
| 8. | 2021 Deferral Account Balance receivable from Ratepayers | | 12,123.59 | 8,616.31 |

BREAKDOWN OF SHORT TERM STORAGE DEFERRAL ACCOUNT (STSDA) - UNION RATE ZONES

| Line No. | Particulars (\$000's) | Col. 1 Board-Approved 2013 | Col. 2 Actual 2020 | Col. 3 Actual 2021 |
|----------|---|----------------------------------|--------------------------|--------------------------|
| | Revenue | | | |
| 1. | C1 Off-Peak Storage | 500 | 1,002 | 433 |
| 2. | Supplemental Balancing Services | 2,000 | 1,016 | 640 |
| 3. | Gas Loans | | 1 | 1 |
| 4. | LBA | | 0 | 0 |
| 5. | | 2,500 | 2,019 | 1,075 |
| 6. | C1 ST Firm Peak Storage | 7,883 | 2,715 | 1,536 |
| 7. | Total Revenue ⁽¹⁾ | 10,383 | 4,735 | 2,610 |
| | Costs | | | |
| 8. | O&M ⁽²⁾ | 3,810 | 782 | 1,004 |
| 9. | UFG ⁽³⁾ | 316 | 114 | 266 |
| 10. | Compressor Fuel ⁽⁴⁾ | 1,201 | 196 | 257 |
| 11. | Total Costs | 5,327 | 1,091 | 1,528 |
| 12. | Net Revenue (line 7 - 11) | 5,056 | 3,644 | 1,082 |
| 13. | Less Shareholder Portion (10%) | 505 | 364 | 108 |
| 14. | Ratepayer Portion | 4,551 | 3,279 | 974 |
| 15. | Approved in Rates | 4,551 | 4,551 | 4,551 |
| 16. | Deferral balance payable to / (collectable from) ratepayers | (0) | (1,272) | (3,577) |

Notes:

- (1) Based on short-term storage services provided
- (2) Revenue Requirement on 11.3 PJ's of board approved excess in-franchise storage capacity
- (3) Based on short-term storage volumes in proportion to total volumes
- (4) Based on short-term storage activity in proportion to total actual storage activity

ENBRIDGE GAS INC.
2021 Storage Space & Deliverability

| Line No. | Particulars | 2021 (1) | |
|-------------|--|----------------------|-------------------------------|
| | | Storage Space (2) | Storage Deliverability (2) |
| | | (PJ) (a) | (GJ/d) (b) |
| | <u>Union North Rate Zone</u> | | |
| 1 | Rate 01 | 12.2 | 212,035 |
| 2 | Rate 10 | 2.9 | 60,957 |
| 3 | Rate 20 | 2.4 | 35,273 |
| 4 | Rate 25 | - | - |
| 5 | Rate 100 | 0.1 | 1,139 |
| 6 | Total Union North Rate Zone | <u>17.5</u> | <u>309,405</u> |
| | <u>Union South Rate Zone</u> | | |
| 7 | Rate M1 | 40.0 | 990,924 |
| 8 | Rate M2 | 10.6 | 318,002 |
| 9 | Rate M4 | 2.9 | 174,198 |
| 10 | Rate M5 | 0.0 | 291 |
| 11 | Rate M7 | 2.1 | 67,205 |
| 12 | Rate M9 | 0.3 | 9,448 |
| 13 | Rate M10 | 0.0 | 145 |
| 14 | Rate T1 | 1.5 | 40,947 |
| 15 | Rate T2 | 9.3 | 200,945 |
| 16 | Rate T3 | 3.2 | 70,931 |
| 17 | Total Union South Rate Zone | <u>70.0</u> | <u>1,873,036</u> |
| | <u>Ex-Franchise</u> | | |
| 18 | Excess Utility Storage | 3.0 (3) | 35,816 |
| 19 | Rate C1 | - | - |
| 20 | Rate M12 | - | - |
| 21 | Rate M13 | - | - |
| 22 | Rate M16 | - | - |
| 23 | Total Ex-Franchise | <u>3.0</u> | <u>35,816</u> |
| 24 | System Integrity Space | 9.5 | - |
| 25 | Total Union Rate Zone | <u>100.0</u> | <u>2,218,257</u> |
| | <u>EGD Rate Zone</u> | | |
| 26 | Rate 1 | 61.2 | 1,208,141 |
| 27 | Rate 6 | 58.7 | 962,711 |
| 28 | Rate 9 | - | - |
| 29 | Rate 100 | - | - |
| 30 | Rate 110 | 2.2 | 5,076 |
| 31 | Rate 115 | 0.5 | 2,013 |
| 32 | Rate 125 | - | - |
| 33 | Rate 135 | - | - |
| 34 | Rate 145 | 0.3 | - |
| 35 | Rate 170 | 0.8 | - |
| 36 | Rate 200 | 2.0 | 20,355 |
| 37 | Total EGD Rate Zone | <u>125.8</u> | <u>2,198,296</u> |
| 38 | Total Enbridge Gas (line 25 + line 37) | <u>225.8</u> | <u>4,416,553</u> |

Notes:

- (1) Allocation to rate classes using OEB-approved cost allocation methodologies.
- (2) Union rate zone storage space based on actual W21/22 usage and storage deliverability based on forecast W21/22 requirements. EGD rate zone storage space and deliverability based on 2021 Gas Supply plan.
- (3) EB-2022-0110, Exhibit E, Tab 1, page 6.

SUMMARY OF NON-UTILITY STORAGE BALANCES - UNION RATE ZONES

| <u>Date</u> | <u>Entitlement</u> (PJ) | <u>Balance</u> (PJ) | <u>% Full</u> (%) | <u>Date</u> | <u>Entitlement</u> (PJ) | <u>Balance</u> (PJ) | <u>% Full</u> (%) |
|-------------|----------------------------|------------------------|----------------------|-------------|----------------------------|------------------------|----------------------|
| 1-Oct-21 | 127.6 | 118.8 | 93.1% | 1-Nov-21 | 127.6 | 121.4 | 95.1% |
| 2-Oct-21 | 127.6 | 119.0 | 93.2% | 2-Nov-21 | 127.6 | 121.4 | 95.2% |
| 3-Oct-21 | 127.6 | 118.9 | 93.2% | 3-Nov-21 | 127.6 | 121.2 | 95.0% |
| 4-Oct-21 | 127.6 | 118.6 | 93.0% | 4-Nov-21 | 127.6 | 121.2 | 95.0% |
| 5-Oct-21 | 127.6 | 118.5 | 92.9% | 5-Nov-21 | 127.6 | 121.4 | 95.2% |
| 6-Oct-21 | 127.6 | 118.6 | 93.0% | 6-Nov-21 | 127.6 | 121.6 | 95.3% |
| 7-Oct-21 | 127.6 | 118.7 | 93.0% | 7-Nov-21 | 127.6 | 121.8 | 95.4% |
| 8-Oct-21 | 127.6 | 118.7 | 93.0% | 8-Nov-21 | 127.6 | 121.7 | 95.4% |
| 9-Oct-21 | 127.6 | 118.9 | 93.2% | 9-Nov-21 | 127.6 | 122.2 | 95.8% |
| 10-Oct-21 | 127.6 | 119.0 | 93.3% | 10-Nov-21 | 127.6 | 122.9 | 96.3% |
| 11-Oct-21 | 127.6 | 119.2 | 93.4% | 11-Nov-21 | 127.6 | 123.8 | 97.0% |
| 12-Oct-21 | 127.6 | 119.2 | 93.4% | 12-Nov-21 | 127.6 | 124.5 | 97.6% |
| 13-Oct-21 | 127.6 | 119.3 | 93.5% | 13-Nov-21 | 127.6 | 125.1 | 98.1% |
| 14-Oct-21 | 127.6 | 119.3 | 93.5% | 14-Nov-21 | 127.6 | 125.2 | 98.1% |
| 15-Oct-21 | 127.6 | 119.4 | 93.6% | 15-Nov-21 | 127.6 | 125.2 | 98.1% |
| 16-Oct-21 | 127.6 | 119.6 | 93.8% | 16-Nov-21 | 127.6 | 125.4 | 98.3% |
| 17-Oct-21 | 127.6 | 119.7 | 93.9% | 17-Nov-21 | 127.6 | 125.9 | 98.7% |
| 18-Oct-21 | 127.6 | 119.7 | 93.9% | 18-Nov-21 | 127.6 | 126.1 | 98.9% |
| 19-Oct-21 | 127.6 | 119.7 | 93.8% | 19-Nov-21 | 127.6 | 125.9 | 98.7% |
| 20-Oct-21 | 127.6 | 119.7 | 93.9% | 20-Nov-21 | 127.6 | 125.9 | 98.7% |
| 21-Oct-21 | 127.6 | 119.8 | 93.9% | 21-Nov-21 | 127.6 | 125.9 | 98.7% |
| 22-Oct-21 | 127.6 | 119.8 | 93.9% | 22-Nov-21 | 127.6 | 125.1 | 98.1% |
| 23-Oct-21 | 127.6 | 119.9 | 94.0% | 23-Nov-21 | 127.6 | 124.3 | 97.4% |
| 24-Oct-21 | 127.6 | 120.1 | 94.1% | 24-Nov-21 | 127.6 | 124.1 | 97.3% |
| 25-Oct-21 | 127.6 | 120.1 | 94.1% | 25-Nov-21 | 127.6 | 124.0 | 97.2% |
| 26-Oct-21 | 127.6 | 120.2 | 94.2% | 26-Nov-21 | 127.6 | 123.9 | 97.1% |
| 27-Oct-21 | 127.6 | 120.3 | 94.3% | 27-Nov-21 | 127.6 | 123.5 | 96.8% |
| 28-Oct-21 | 127.6 | 120.6 | 94.5% | 28-Nov-21 | 127.6 | 122.9 | 96.3% |
| 29-Oct-21 | 127.6 | 120.9 | 94.8% | 29-Nov-21 | 127.6 | 122.2 | 95.8% |
| 30-Oct-21 | 127.6 | 121.1 | 94.9% | 30-Nov-21 | 127.6 | 121.7 | 95.4% |
| 31-Oct-21 | 127.6 | 121.3 | 95.1% | | | | |

ALLOCATION OF SHORT TERM PEAK STORAGE REVENUES
BETWEEN UTILITY AND NON UTILITY - UNION RATE ZONES

| Line No. | Particulars | Utility Storage Space (PJs) | Short Term Peak Storage Sold (PJs) | Revenue from Short Term Peak Storage (\$ millions) |
|-------------|---|--------------------------------------|---|--|
| 1 | Net Revenues from Short Term Peak Storage | | | 1.5 |
| 2 | Total Short Term Peak Storage Sales | | 3.0 | |
| 3 | Storage Space reserved for Utility | 100.0 | | |
| 4 | Utility Space Requirement | 97.0 | | |
| 5 | Excess Utility Storage Space ⁽¹⁾ | 3.0 | | |
| 6 | Total Utility Short Term Peak Storage Sales ⁽²⁾ | | 3.0 | |
| 7 | Total Non Utility Short Term Peak Storage Sales | | 0.0 | |
| 8 | Short Term Peak Storage Net Revenues - Utility ⁽³⁾ | | | 1.5 |
| 9 | Short Term Peak Storage Net Revenues - Non Utility ⁽⁴⁾ | | | - |

Notes:

(1) line 3 - line 4

(2) line 2

(3) line 6 /line 2 *line

(4) line 7/ line 2* line 1

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2019 ESM (EB-2020-0134), 2017-2018 DSM (EB-2020-0067)
DISPOSITIONS DISPOSED OF DURING 2021

| Line No. | Particulars (\$000) | 2021 | | | Total (d) = (a) + (b) + (c) |
|-------------|---|---|--|---------------------|--------------------------------|
| | | 2019 ESM Deferral EB-2020-0134 (a) | 2017-18 DSM Deferral EB-2020-0067 (b) | Interest (1) (c) | |
| 1. | Prospective Recovery/(Refund) - Delivery | (2,233) | (1,990) | (63) | (4,285) |
| 2. | Prospective Recovery/(Refund) - Gas Supply Transportation | (1,447) | | (21) | (1,469) |
| 3. | Prospective Recovery/(Refund) - Gas Supply Commodity | 1,698 | | 25 | 1,723 |
| 4. | Sub-Total | (1,982) | (1,990) | (59) | (4,030) |
| 5. | Manual Re-bills and other one-time billing adjustments | | | | 20 |
| 6. | Grand Total | | | | (4,010) |

(1) Interest forecasted to December 31, 2022.

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES2017/2018 DSM DEFERRAL DISPOSITION (EB-2020-0067)DISPOSITION PERIOD - APRIL 1, 2021 TO SEPTEMBER 30, 2021

| | | | 2021 | | | | | | | |
|----------|--|------------|-----------------------------|-----------------------|-------------------------|---|---|--|--|------------------|
| Line No. | Particulars | Rate Class | Forecast Volume (10³m³) (1) | Actual Volume (10³m³) | Volume Variance (10³m³) | 2017 DSM Unit Rate for Prospective Recovery/(Refund) (cents/m³) | 2018 DSM Unit Rate for Prospective Recovery/(Refund) (cents/m³) | Forecast (\$000) | Actual (\$000) | Variance (\$000) |
| | | | (a) | (b) | (c) | (d) | (e) | (f) = ((a) * (d)/100) + ((a) * (e)/100)) | (g) = ((b) * (d)/100) + ((b) * (e)/100)) | (h) = (f) - (g) |
| | <u>General Service for Prospective Recovery(Refund) - Delivery</u> | | | | | | | | | |
| 1 | Small Volume General Service | 01 | 218,218 | 206,105 | 12,113 | (0.9140) | (0.8186) | (3,781) | (3,571) | (210) |
| 2 | Large Volume General Service | 10 | 97,893 | 82,334 | 15,559 | (0.8698) | (1.3393) | (2,163) | (1,819) | (344) |
| 3 | Small Volume General Service | M1 | 708,032 | 724,452 | (16,420) | 2.3352 | 2.5733 | 34,754 | 35,560 | (806) |
| 4 | Large Volume General Service | M2 | 373,184 | 322,222 | 50,962 | (0.5157) | (0.7207) | (4,614) | (3,984) | (630) |
| 5 | Total General Service for Prospective Recovery (Refund) - Delivery | | <u>1,397,327</u> | <u>1,335,112</u> | <u>62,215</u> | | | <u>24,196</u> | <u>26,186</u> | <u>(1,990)</u> |
| 6 | Total | | | | | | | <u>24,196</u> | <u>26,186</u> | <u>(1,990)</u> |

Notes:

(1) Forecast volume for the period April 1, 2021 to September 30, 2021.

DEFERRAL VARIANCE CLEARING ACCOUNT - UNION RATE ZONES
2019 DEFERRAL DISPOSITION (EB-2020-0134)
DISPOSITION PERIOD - OCTOBER 1, 2021 TO DECEMBER 31, 2021

| Line No. | Particulars | Rate Class | 2021 | | | | | | |
|---|---|------------|--|--|--|--|---------------------|----------------------|---------------------|
| | | | Forecast Volume (10 ³ m ³) (1) | Actual Volume (10 ³ m ³) | Volume Variance (10 ³ m ³) | Unit Rate for Prospective Recovery/(Refund) (cents/m ³) (2) | Forecast (\$000) | Actual (\$000) | Variance (\$000) |
| | | | (a) | (b) | (c) | (d) | (e) = (a) * (d)/100 | (f) = (b) * (d)/ 100 | (g) = (c) - (f) |
| <u>General Service for Prospective Recovery(Refund) - Delivery</u> | | | | | | | | | |
| 1 | Small Volume General Service | 01 | 321,283 | 275,592 | 45,691 | (1.0715) | (3,443) | (2,953) | (490) |
| 2 | Large Volume General Service | 10 | 113,056 | 83,501 | 29,555 | (1.1691) | (1,322) | (976) | (346) |
| 3 | Small Volume General Service | M1 | 951,810 | 822,199 | 129,611 | (0.6869) | (6,538) | (5,648) | (890) |
| 4 | Large Volume General Service | M2 | 429,887 | 313,806 | 116,081 | (0.4369) | (1,878) | (1,371) | (507) |
| 5 | Total General Service for Prospective Recovery (Refund) - Delivery | | <u>1,816,036</u> | <u>1,495,097</u> | <u>320,939</u> | | <u>(13,180)</u> | <u>(10,948)</u> | <u>(2,233)</u> |
| <u>General Service for Prospective Recovery(Refund) - Gas Supply Transportation</u> | | | | | | | | | |
| 6 | Small Volume General Service-NW | 01 | 90,838 | 80,740 | 10,098 | (8.0456) | (7,308) | (6,496) | (812) |
| 7 | Small Volume General Service-NE | 01 | 230,446 | 194,851 | 35,595 | (0.4405) | (1,015) | (858) | (157) |
| 8 | Large Volume General Service-NW | 10 | 27,145 | 19,561 | 7,584 | (5.4548) | (1,481) | (1,067) | (414) |
| 9 | Large Volume General Service-NE | 10 | 84,374 | 62,677 | 21,697 | (0.2959) | (250) | (185) | (64) |
| 10 | Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation | | <u>432,803</u> | <u>357,830</u> | <u>74,973</u> | | <u>(10,054)</u> | <u>(8,607)</u> | <u>(1,447)</u> |
| <u>Prospective Recovery/(Refund) - Gas Supply Commodity</u> | | | | | | | | | |
| 11 | Small Volume General Service | M1 | 889,983 | 771,375 | 118,608 | 0.7902 | 7,033 | 6,095 | 937 |
| 12 | Large Volume General Service | M2 | 224,466 | 139,468 | 84,998 | 0.7902 | 1,774 | 1,102 | 672 |
| 13 | Firm Com/Ind Contract | M4 | 20,550 | 15,982 | 4,568 | 0.7902 | 162 | 126 | 36 |
| 14 | Interruptible Com/Ind Contract | M5 | 2,744 | 625 | 2,119 | 0.7902 | 22 | 5 | 17 |
| 15 | Special Large Volume Contract | M7 | 7,927 | 7,534 | 393 | 0.7902 | 63 | 60 | 3 |
| 16 | Large Wholesale | M9 | 10,631 | 6,454 | 4,177 | 0.7902 | 84 | 51 | 33 |
| 17 | Small Wholesale | M10 | 125 | 101 | 24 | 0.7902 | 1 | 1 | 0 |
| 18 | Total Prospective Recovery (Refund) - Gas Supply Commodity | | <u>1,156,427</u> | <u>941,540</u> | <u>214,886</u> | | <u>9,138</u> | <u>7,440</u> | <u>1,698</u> |
| 19 | Total | | | | | | <u>(14,096)</u> | <u>(12,115)</u> | <u>(1,982)</u> |

Notes:

(1) Forecast volume for the period October 1, 2021 to December 31, 2021.

(2) Unit rate for prospective recovery/refund for each rate class equal to the gas supply commodity weighted-average unit rate.

UNION RATE ZONES
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133) - Base Rates and Y-Factor

| Line No. | Particulars | | Rate 01 (a) | Rate 10 (b) | Rate M1 (c) | Rate M2 (d) | Net Account Balance (e) |
|---|---|-----|----------------|----------------|----------------|----------------|-------------------------------|
| <u>Base Rates</u> | | | | | | | |
| 1 | 2021 Target NAC: m ³ | | 2,889.4 | 171,539.6 | 2,775.7 | 168,419.3 | |
| 2 | 2021 Actual NAC: m ³ | | 2,765.6 | 151,410.7 | 2,667.6 | 149,839.7 | |
| 3 | Actual change in NAC: m ³ (line 1 - 2) | | 123.7 | 20,128.9 | 108.1 | 18,579.6 | |
| <u>Y Factor Rates</u> | | | | | | | |
| 4 | 2021 Target NAC: m ³ | | 2,829.8 | 166,842.2 | 2,691.8 | 169,476.8 | |
| 5 | 2021 Actual NAC: m ³ | | 2,765.6 | 151,410.7 | 2,667.6 | 149,839.7 | |
| 6 | Actual change in NAC: m ³ (line 4 - 5) | | 64.2 | 15,431.5 | 24.2 | 19,637.1 | |
| 7 | 2013 Board-approved number of Customers at December | | 323,287.0 | 2,064.0 | 1,067,757.0 | 6,778.0 | 1,399,886.0 |
| <u>Base Rates</u> | | | | | | | |
| 8 | Annual Volume Impact (10 ³ m ³) | (1) | 39,588 | 41,294 | 114,193 | 126,241 | 321,316 |
| 9 | 2021 Net Annual Average Delivery Rate (\$/m3) | (2) | \$0.087 | \$0.053 | \$0.037 | \$0.034 | |
| 10 | 2021 Net Annual Average Storage Rate (\$/m3) | (3) | \$0.047 | \$0.034 | \$0.008 | \$0.007 | |
| 11 | Delivery Rate Annual Balance Amount (\$000) | (4) | \$3,461 | \$2,168 | \$4,221 | \$4,255 | \$14,106 |
| 12 | Storage Rate Annual Balance Amount (\$000) | (4) | \$1,873 | \$1,407 | \$916 | \$886 | \$5,081 |
| <u>Y Factor Rates</u> | | | | | | | |
| 13 | Annual Volume Impact (10 ³ m ³) | (1) | 20,531 | 31,672 | 25,241 | 133,236 | 210,681 |
| 14 | 2021 Net Annual Average Delivery Rate (\$/m3) | (2) | \$0.006 | \$0.009 | \$0.013 | \$0.011 | |
| 15 | 2021 Net Annual Average Storage Rate (\$/m3) | (3) | \$0.000 | \$0.000 | \$0.000 | \$0.000 | |
| 16 | Delivery Rate Annual Balance Amount (\$000) | (4) | \$133 | \$276 | \$317 | \$1,523 | \$2,249 |
| 17 | Storage Rate Annual Balance Amount (\$000) | (4) | \$0 | \$0 | \$0 | \$0 | \$0 |
| <u>Total Annual Balance Amounts (\$000)</u> | | | | | | | |
| 18 | Total Delivery Rate Annual Balance Amount (line 11+16) | | \$3,594 | \$2,444 | \$4,539 | \$5,779 | \$16,355.3 |
| 19 | Total Storage Rate Annual Balance Amount (line 12+17) | | \$1,873 | \$1,407 | \$916 | \$886 | \$5,080.9 |
| 20 | Storage Cost Annual Balance Amount (\$000) | | (\$201) | (\$99) | (\$890) | (\$1,249) | (\$2,438) |
| 21 | Interest (\$000) | (5) | \$64 | \$45 | \$65 | \$65 | \$239 |
| 22 | Total Deferral Account Amounts (\$000) (line 18+19+20+21) | | \$5,330 | \$3,797 | \$4,629 | \$5,481 | \$19,237 |

Notes:

- (1) The annual volume is obtained from a monthly calculation of approved customers and the monthly usage variance.
- (2) The Net Annual Average Delivery Rate is the volume-weighted average of Board-approved monthly unit rates in effect
- (3) The Net Annual Average Storage Rate is the volume-weighted average of Board-approved monthly unit rates in effect
- (4) The annual revenue is obtained from a monthly calculation of volumes (lines 8 and 13) and the monthly unit delivery and storage rates (lines 9, 10, 14 and 15).
- (5) Interest is calculated on the monthly opening balance in the deferral account in accordance with the methodology approved by the Board in EB-2006-0117. Interest is calculated to Dec 31, 2022.

CALCULATION OF 2021 TRANSPORTATION REVENUES ON THE LOBO D/BRIGHT C/DAWN H COMPRESSOR
PROJECT COST DEFERRAL ACCOUNT
UNION RATE ZONES

| Particulars | Volume (TJ/d) ⁽¹⁾ | Revenue (\$000's) ⁽²⁾ | Project Surplus Allocation (%) | Allocation (\$000's) |
|--------------|---------------------------------|-------------------------------------|-----------------------------------|-------------------------|
| | (a) | (b) | (a) | (d) = (b) x (c) |
| <u>2021</u> | | | | |
| January | 30 | 111 | 100% | 111 |
| February | 30 | 111 | 100% | 111 |
| March | 30 | 111 | 100% | 111 |
| April | 30 | 111 | 100% | 111 |
| May | 30 | 111 | 100% | 111 |
| June | 30 | 111 | 100% | 111 |
| July | 30 | 111 | 100% | 111 |
| August | 30 | 111 | 100% | 111 |
| September | 30 | 111 | 100% | 111 |
| October | 30 | 111 | 100% | 111 |
| November | 30 | 111 | 100% | 111 |
| December | 30 | 111 | 100% | 111 |
| Total | | 1,337 | | 1,337 |

Notes

⁽¹⁾ Capacity of 30,393 GJ/d assumed to be sold long term.

⁽²⁾ Sold at the Dawn to Parkway M12 Rate of \$3.665 \$/GJ

ALLOCATION AND DISPOSITION OF
2021 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2021 deferral and variance account balances identified at Exhibit C, Tab 1, Schedule 1.
2. Enbridge Gas proposes to dispose of the approved 2021 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2023.
3. This exhibit of evidence is organized as follows:
 1. Allocation of Deferral and Variance Accounts
 - 1.1 EGI Accounts
 - 1.2 EGD Rate Zone Accounts
 - 1.3 Union Rate Zones' Accounts
 2. Disposition of Deferral and Variance Accounts
 3. General Service Bill Impacts

1. Allocation of Deferral and Variance Accounts

4. In accordance with the OEB's EB-2017-0306/EB-2017-0307 Decision and Order (MAADs Decision), the OEB approved new EGI deferral and variance accounts that apply to both the EGD rate zone and Union rate zones effective January 1, 2019. The applicability of other deferral and variance accounts that were approved to continue during the deferred rebasing period is for either the EGD rate zone or the Union rate zones.

1.1. EGI Accounts

5. The OEB previously approved¹ the following deferral and variance accounts for Enbridge Gas that are applicable to both the EGD and Union rate zones:
- Accounting Policy Changes Deferral Account (APCDA),
 - Earnings Sharing Mechanism Deferral Account (ESMDA),
 - Tax Variance Deferral Account (TVDA),
 - Expansion of Natural Gas Distribution System Variance Account (ENGDSVA),
 - IRP Operating Costs Deferral Account,
 - IRP Capital Costs Deferral Account, and
 - Impacts Arising from the COVID-19 Emergency Deferral Account (IACEDA).
6. Enbridge Gas is proposing to dispose of the 2021 balance in the TVDA and the IRP Operating Costs Deferral Account as part of this application. The balance in the APCDA and IACEDA are not proposed for disposition as part of this application, as described at Exhibit C, Tab 1. There is no balance for the ESMDA, ENGDSVA and IRP Capital Costs Deferral Account, as shown at Exhibit C, Tab 1, Schedule 1.
7. The 2021 TVDA balance, including interest, is a credit of \$19.390 million as shown at Exhibit C, Tab 1, Schedule 1. Consistent with the methodology approved by the OEB in previous years, Enbridge Gas has split the credit balance of \$19.390 million between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone.² Splitting the \$19.390 million TVDA credit balance in proportion to 2018 actual rate base results in a credit of \$10.236 million being cleared to the EGD rate zone and a credit of \$9.154 million being cleared to the Union rate zones. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.

¹ EB-2017-0306/EB-2017-0307 Decision and Order established the APCDA, ESMDA and TVDA. The ENGDSVA was established in accordance with Section 4 of Ontario Regulation 24/19. The IRP Operating Costs Deferral Account and the IRP Capital Costs Deferral Account were established in accordance with the EB-2020-0091 Decision and Order.

² EB-2020-0134 Decision and Order, May 6, 2021, page 16.

8. The 2021 IRP Operating Cost Deferral Account balance, including interest, is a debit of \$0.058 million as shown at Exhibit C, Tab 1, Schedule 1. Consistent with the TVDA, Enbridge Gas has split the debit balance of \$0.058 million between the EGD and Union rate zones in proportion to the 2018 actual rate base for each rate zone.³ Splitting the \$0.058 million debit balance in proportion to 2018 actual rate base results in a debit of \$0.031 million being cleared to the EGD rate zone and a debit of \$0.027 million being cleared to the Union rate zones. The details of the split to rate zones is provided at Exhibit F, Tab 1, Schedule 1.
9. Enbridge Gas has allocated the split balance of the TVDA and IRP Operating Cost Deferral Account to rate classes in each rate zone in proportion to 2018 rate base for the EGD rate zone and 2013 rate base for the Union rate zones. The rate base allocation for each rate zone is taken from the last fully allocated cost study prepared for each rate zone. The allocation to EGD rate classes is provided at Exhibit F, Tab 2, Schedule 3. The allocation to Union rate classes is provided at Exhibit F, Tab 3, Schedule 2.

1.2 EGD Rate Zone Accounts

10. The 2021 deferral and variance account balances to be cleared to the EGD rate zone are provided at Exhibit F, Tab 2, Schedule 2, including the EGD rate zone allocation of the EGI accounts.
11. The 2021 EGD rate zone deferral and variance account balances are allocated to the customer classes using the same methodologies that the OEB approved in previous years.
12. The allocation of account balances to EGD rate classes based on cost drivers for each type of account is provided at Exhibit F, Tab 2, Schedule 3. A summary of the

³ EB-2020-0134 Decision and Order, May 6, 2021, page 16.

allocation of account balances by rate class and type of service is provided at Exhibit F, Tab 2, Schedule 4.

1.3 Union Rate Zones' Accounts

13. The 2021 deferral and variance account balances to be cleared to the Union rate zones are provided at Exhibit F, Tab 3, Schedule 1, including the Union rate zones allocation of the EGI accounts.
14. The 2021 Union rate zones' deferral and variance account balances are allocated to the customer classes using the same methodologies that the OEB approved in previous years except for the Deferral Clearing Variance Account (179-132) in the Union rate zone.
15. With the harmonization of Enbridge Gas's customer information system (CIS) in 2021, the Union rate zone is no longer able to identify and allocate DCVA balances to rate classes. Consistent with the EGD rate zone Deferred Rebate Account allocation, Enbridge Gas proposes to split the DCVA balance between general service and contract customers. The allocation of general service and contract customer balances to rate classes is based on respective volumes. Please refer to Exhibit E, Tab 1 for background on the DCVA balance, and Exhibit F, Tab 3, Schedule 3 for the proposed allocation.
16. The allocation of account balances to Union South and Union North rate classes is provided at Exhibit F, Tab 3, Schedule 2.

2. Disposition of Deferral and Variance Accounts

17. Enbridge Gas proposes to dispose of the approved 2021 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as January 1, 2023

18. Enbridge Gas proposes to dispose of the 2021 deferral and variance account balances as a one-time billing adjustment. The billing adjustment will appear as a separate line item on customers' bills, the earliest being January 2023. The one-time billing adjustment will be derived for each customer by applying the disposition unit rates to each customer's actual consumption volume or contract demand, as applicable, for the period January 1, 2021 to December 31, 2021.
19. The unit rates for disposition by rate class and service type are provided at Exhibit F, Tab 2, Schedule 1 and Schedule 5 for the EGD rate zone. The unit rates for disposition for the Union rate zones, including a summary of the balances to be disposed of to ex-franchise rate classes are provided at Exhibit F, Tab 3, Schedule 4.

3. General Service Bill Impacts

20. For a Rate 1 sales service and western t-service customer in the EGD rate zone with annual consumption of 2,400 m³, the one-time billing adjustment charge is \$5.01.⁴ /u
21. For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m³, the one-time billing adjustment charge is \$9.34. For a Rate M1 bundled direct purchase (DP) residential customer, the one-time billing adjustment charge is \$1.91. /u
22. For a Rate 01 sales service and bundled DP residential customer in Union North West with annual consumption of 2,200 m³, the one-time billing adjustment credit is \$17.33. /u

⁴ In addition to the EGD rate zone 2021 Deferral bill impacts, the allocation of Union rate zone deferrals to Rate M12 results in a bill impact of approximately \$1.00 to a typical Rate 1 residential customer in the EGD rate zone.

23. For a Rate 01 sales service and bundled DP residential customer in Union North East with annual consumption of 2,200 m³, the one-time billing adjustment charge is \$7.78.

/u

24. Bill impacts of the proposed disposition are provided at Exhibit F, Tab 2, Schedule 6 for the EGD rate zone and Exhibit F, Tab 3, Schedule 5 for the Union rate zones.

ENBRIDGE GAS INC.
Split of EGI Account Balances to Rate Zones

| Line No. | Particulars (\$ millions) | Allocator | Account Balance | | |
|--|---------------------------|------------------------------|-----------------|--------------|-------------|
| | | 2018 Actual Rate Base (1) | Principal (2) | Interest (2) | Total |
| | | (a) | (b) | (c) | (d) = (b+c) |
| <u>2021 Tax Variance Deferral Account</u> | | | | | |
| 1 | EGD rate zone | 6,729 | (10.116) | (0.120) | (10.236) |
| 2 | Union rate zones | 6,018 | (9.047) | (0.107) | (9.154) |
| 3 | Total | 12,748 | (19.163) | (0.227) | (19.390) |
| <u>2021 IRP Operating Costs Deferral Account</u> | | | | | |
| 4 | EGD | 6,729 | 0.030 | 0.000 | 0.031 |
| 5 | Union | 6,018 | 0.027 | 0.000 | 0.027 |
| 6 | Total | 12,748 | 0.058 | 0.000 | 0.058 |

Note:

- (1) 2018 actual rate base per EB-2019-0105, Exhibit B, Tab 2, Appendix B, Schedule 1 for the EGD rate zone and EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 4 for the Union rate zones.
- (2) Allocated in proportion to column (a).

ENBRIDGE GAS INC.
EGD RATE ZONE
UNIT RATE AND TYPE OF SERVICE: CLEARING IN JANUARY 2023

| | | COL.1 |
|---|---------------------|--|
| | | <u>UNIT RATE</u> (\$/m ³) |
| <u>Bundled Services:</u> | | |
| RATE 1 | - SYSTEM SALES | 0.2086 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.2572 |
| | - DAWN T-SERVICE | 0.2572 |
| | - WESTERN T-SERVICE | 0.2086 |
| RATE 6 | - SYSTEM SALES | 0.2527 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.3013 |
| | - DAWN T-SERVICE | 0.3013 |
| | - WESTERN T-SERVICE | 0.2527 |
| RATE 9 | - SYSTEM SALES | 0.0151 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0000 |
| | - DAWN T-SERVICE | 0.0000 |
| | - WESTERN T-SERVICE | 0.0000 |
| RATE 100 | - SYSTEM SALES | 0.0675 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.1160 |
| | - DAWN T-SERVICE | 0.1160 |
| | - WESTERN T-SERVICE | 0.0000 |
| RATE 110 | - SYSTEM SALES | 0.0209 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0694 |
| | - DAWN T-SERVICE | 0.0694 |
| | - WESTERN T-SERVICE | 0.0209 |
| RATE 115 | - SYSTEM SALES | 0.0127 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0613 |
| | - DAWN T-SERVICE | 0.0613 |
| | - WESTERN T-SERVICE | 0.0000 |
| RATE 135 | - SYSTEM SALES | 0.0123 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0000 |
| | - DAWN T-SERVICE | 0.0609 |
| | - WESTERN T-SERVICE | 0.0123 |
| RATE 145 | - SYSTEM SALES | 0.0000 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0000 |
| | - DAWN T-SERVICE | 0.0734 |
| | - WESTERN T-SERVICE | 0.0000 |
| RATE 170 | - SYSTEM SALES | 0.0200 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0685 |
| | - DAWN T-SERVICE | 0.0685 |
| | - WESTERN T-SERVICE | 0.0000 |
| RATE 200 | - SYSTEM SALES | 0.0607 |
| | - BUY/SELL | 0.0000 |
| | - ONTARIO T-SERVICE | 0.1092 |
| | - DAWN T-SERVICE | 0.1092 |
| | - WESTERN T-SERVICE | 0.0000 |
| <u>Unbundled Services (Billing based on CD):</u> | | |
| RATE 125 | - All | (0.3318) |
| RATE 300 | - All | (1.5672) |
| RATE 332 | - All | (0.3320) |

ENBRIDGE GAS INC.
EGD RATE ZONE
DETERMINATION OF BALANCES TO BE CLEARED
FROM THE 2021 DEFERRAL AND VARIANCE ACCOUNTS

| | | COL. 1 | COL. 2 | COL. 3 |
|----------------------|---|--------------------------------------|---------------------|----------------------------------|
| ITEM NO. | | PRINCIPAL FOR CLEARING (\$000) | INTEREST (\$000) | TOTAL FOR CLEARING (\$000) |
| <u>EGD RATE ZONE</u> | | | | |
| 1. | TRANSACTIONAL SERVICES D/A | (3,904.1) | (35.4) | (3,939.6) |
| 2. | UNACCOUNTED FOR GAS V/A | 753.9 | 4.5 | 758.4 |
| 3. | STORAGE AND TRANSPORTATION D/A | 7,942.5 | 97.0 | 8,039.5 |
| 4. | DEFERRED REBATE ACCOUNT | 4,359.4 | 53.5 | 4,412.9 |
| 5. | OEB COST ASSESSMENT VARIANCE ACCOUNT | 2,550.3 | 31.5 | 2,581.8 |
| 6. | AVERAGE USE TRUE-UP V/A | 14,934.3 | 135.5 | 15,069.8 |
| 7. | TRANSITION IMPACT OF ACCT CHANGE D/A | 4,435.8 | - | 4,435.8 |
| 8. | DAWN ACCESS COSTS D/A | 1,968.0 | 17.9 | 1,985.9 |
| 9. | EGD RATE ZONE SUB-TOTAL | 33,040.0 | 304.5 | 33,344.6 |
| <u>EGI ACCOUNTS</u> | | | | |
| 10. | TAX VARIANCE - ACCELERATED CCA - EGD RATE ZONE PORTION | (10,115.6) | (119.9) | (10,235.5) |
| 11. | IRP OPERATING COST DEFERRAL ACCOUNT - EGD RATE ZONE PORTION | 30.5 | 0.3 | 30.7 |
| 12. | EGI SUB-TOTAL | (10,085.1) | (119.7) | (10,204.8) |
| 13. | TOTAL | 22,954.9 | 184.9 | 23,139.8 |

ENBRIDGE GAS INC.EGD RATE ZONECLASSIFICATION AND ALLOCATION OF DEFERRAL AND VARIANCE ACCOUNT BALANCES

| ITEM NO. | COL. 1 | COL. 2 | COL. 3 | COL. 4 | COL. 5 | COL. 6 | COL. 7 | COL. 8 | COL. 9 | COL. 10 |
|--|------------|------------------|----------------|---------------------|---------|---------------------|----------|------------------------|--------------|---------------------------------|
| | TOTAL | SALES AND WBT | TOTAL SALES | TOTAL DELIVERIES | SPACE | DELIVE- RABILITY | DIRECT | NUMBER OF CUSTOMERS | RATE BASE | BUNDLED ANNUAL DELIVERIES |
| CLASSIFICATION | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) |
| 1. TRANSACTIONAL SERVICES D/A | (3,939.6) | (3,792.2) | | | (50.2) | (97.2) | | | | |
| 2. UNACCOUNTED FOR GAS V/A | 758.4 | | | 758.4 | | | | | | |
| 3. STORAGE AND TRANSPORTATION D/A | 8,039.5 | | | | 2,736.9 | 5,302.6 | | | | |
| 4. DEFERRED REBATE ACCOUNT | 4,412.9 | | | 4,412.9 | | | | | | |
| 5. OEB COST ASSESSMENT VARIANCE ACCOUNT | 2,581.8 | | | | | | | | 2,581.8 | |
| 6. TAX VARIANCE - ACCELERATED CCA - EGI | (10,235.5) | | | | | | | | (10,235.5) | |
| 7. AVERAGE USE TRUE-UP V/A | 15,069.8 | | | | | | 15,069.8 | | | |
| 8. IRP OPERATING COST DEFERRAL ACCOUNT - EGI | 30.7 | | | | | | | | 30.7 | |
| 9. TRANSITION IMPACT OF ACCT CHANGE D/A | 4,435.8 | | | | | | | | 4,435.8 | |
| 10. DAWN ACCESS COSTS D/A | 1,985.9 | | | | | | | | | 1,985.9 |
| TOTAL | 23,139.8 | (3,792.2) | 0.0 | 5,171.3 | 2,686.7 | 5,205.4 | 15,069.8 | 0.0 | (3,187.2) | 1,985.9 |
| ALLOCATION | | | | | | | | | | |
| 1.1 RATE 1 | 9,940.8 | (2,270.6) | 0.0 | 2,183.6 | 1,286.9 | 2,859.2 | 7,134.0 | 0.0 | (2,090.8) | 838.5 |
| 1.2 RATE 6 | 11,974.2 | (1,397.3) | 0.0 | 2,040.9 | 1,233.1 | 2,263.7 | 7,935.8 | 0.0 | (885.7) | 783.7 |
| 1.3 RATE 9 | 0.0 | (0.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1.4 RATE 100 | 33.2 | (6.3) | 0.0 | 15.6 | 7.3 | 17.3 | 0.0 | 0.0 | (6.8) | 6.0 |
| 1.5 RATE 110 | 718.7 | (46.3) | 0.0 | 506.7 | 89.8 | 12.1 | 0.0 | 0.0 | (38.3) | 194.6 |
| 1.6 RATE 115 | 237.1 | (0.5) | 0.0 | 178.3 | 0.0 | 4.8 | 0.0 | 0.0 | (14.0) | 68.5 |
| 1.7 RATE 125 | (30.7) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (30.7) | 0.0 |
| 1.8 RATE 135 | 37.0 | (1.4) | 0.0 | 29.0 | 0.0 | 0.0 | 0.0 | 0.0 | (1.8) | 11.1 |
| 1.9 RATE 145 | 18.2 | 0.0 | 0.0 | 11.4 | 5.6 | 0.0 | 0.0 | 0.0 | (3.1) | 4.4 |
| 1.10 RATE 170 | 172.2 | (3.1) | 0.0 | 117.6 | 16.9 | 0.0 | 0.0 | 0.0 | (4.4) | 45.2 |
| 1.11 RATE 200 | 142.8 | (66.9) | 0.0 | 88.3 | 47.2 | 48.2 | 0.0 | 0.0 | (8.0) | 33.9 |
| 1.12 RATE 300 | (0.2) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.2) | 0.0 |
| 1.13 RATE 332 | (103.4) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (103.4) | 0.0 |
| | 23,139.8 | (3,792.2) | 0.0 | 5,171.3 | 2,686.7 | 5,205.4 | 15,069.8 | 0.0 | (3,187.2) | 1,985.9 |

ENBRIDGE GAS INC.
EGD RATE ZONE
ALLOCATION BY TYPE OF SERVICE

| | COL. 1 | COL. 2 | COL. 3 | COL. 4 | COL. 5 | COL. 6 | COL. 7 | COL. 8 | COL. 9 | COL. 10 |
|---|----------|------------------|----------------|---------------------|---------|---------------------|----------|------------------------|--------------|---------------------------------|
| | TOTAL | SALES AND WBT | TOTAL SALES | TOTAL DELIVERIES | SPACE | DELIVE- RABILITY | DIRECT | NUMBER OF CUSTOMERS | RATE BASE | BUNDLED ANNUAL DELIVERIES |
| | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) | (\$000) |
| <u>Bundled Services:</u> | | | | | | | | | | |
| RATE 1 | | | | | | | | | | |
| - SYSTEM SALES | 9,734.6 | (2,264.0) | - | 2,145.5 | 1,264.5 | 2,809.3 | 7,009.7 | - | (2,054.3) | 823.9 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | 0.1 | - | - | 0.0 | 0.0 | 0.0 | 0.1 | - | (0.0) | 0.0 |
| - DAWN T-SERVICE | 177.9 | - | - | 31.8 | 18.7 | 41.6 | 103.9 | - | (30.5) | 12.2 |
| - WBT | 28.2 | (6.6) | - | 6.2 | 3.7 | 8.1 | 20.3 | - | (5.9) | 2.4 |
| RATE 6 | | | | | | | | | | |
| - SYSTEM SALES | 6,925.4 | (1,329.6) | - | 1,260.0 | 761.2 | 1,397.5 | 4,899.2 | - | (546.8) | 483.8 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | 137.6 | - | - | 21.0 | 12.7 | 23.3 | 81.7 | - | (9.1) | 8.1 |
| - DAWN T-SERVICE | 4,558.4 | - | - | 695.7 | 420.4 | 771.7 | 2,705.4 | - | (301.9) | 267.2 |
| - WBT | 352.8 | (67.7) | - | 64.2 | 38.8 | 71.2 | 249.6 | - | (27.9) | 24.6 |
| RATE 9 | | | | | | | | | | |
| - SYSTEM SALES | 0.0 | (0.0) | - | 0.0 | 0.0 | - | - | - | - | 0.0 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | - | - | - | - | - | - | - | - | - | - |
| - DAWN T-SERVICE | - | - | - | - | - | - | - | - | - | - |
| - WBT | - | - | - | - | - | - | - | - | - | - |
| RATE 100 | | | | | | | | | | |
| - SYSTEM SALES | 8.7 | (6.3) | - | 5.9 | 2.8 | 6.6 | - | - | (2.6) | 2.3 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | 1.9 | - | - | 0.7 | 0.3 | 0.8 | - | - | (0.3) | 0.3 |
| - DAWN T-SERVICE | 22.6 | - | - | 9.0 | 4.2 | 9.9 | - | - | (3.9) | 3.4 |
| - WBT | - | - | - | - | - | - | - | - | - | - |
| RATE 110 | | | | | | | | | | |
| - SYSTEM SALES | 17.4 | (40.4) | - | 38.3 | 6.8 | 0.9 | - | - | (2.9) | 14.7 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | 39.5 | - | - | 26.2 | 4.6 | 0.6 | - | - | (2.0) | 10.1 |
| - DAWN T-SERVICE | 659.2 | - | - | 436.6 | 77.4 | 10.5 | - | - | (33.0) | 167.7 |
| - WBT | 2.5 | (5.9) | - | 5.6 | 1.0 | 0.1 | - | - | (0.4) | 2.1 |
| RATE 115 | | | | | | | | | | |
| - SYSTEM SALES | 0.1 | (0.5) | - | 0.5 | 0.0 | 0.0 | - | - | (0.0) | 0.2 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | 81.1 | - | - | 60.9 | 0.0 | 1.7 | - | - | (4.8) | 23.4 |
| - DAWN T-SERVICE | 155.8 | - | - | 116.9 | 0.0 | 3.2 | - | - | (9.2) | 44.9 |
| - WBT | - | - | - | - | - | - | - | - | - | - |
| RATE 135 | | | | | | | | | | |
| - SYSTEM SALES | 0.3 | (1.3) | - | 1.2 | - | - | - | - | (0.1) | 0.5 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | - | - | - | - | - | - | - | - | - | - |
| - DAWN T-SERVICE | 36.7 | - | - | 27.7 | - | - | - | - | (1.7) | 10.6 |
| - WBT | 0.0 | (0.1) | - | 0.1 | - | - | - | - | (0.0) | 0.0 |
| RATE 145 | | | | | | | | | | |
| - SYSTEM SALES | - | - | - | - | - | - | - | - | - | - |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | - | - | - | - | - | - | - | - | - | - |
| - DAWN T-SERVICE | 18.2 | - | - | 11.4 | 5.6 | - | - | - | (3.1) | 4.4 |
| - WBT | - | - | - | - | - | - | - | - | - | - |
| RATE 170 | | | | | | | | | | |
| - SYSTEM SALES | 1.3 | (3.1) | - | 2.9 | 0.4 | - | - | - | (0.1) | 1.1 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | 99.4 | - | - | 66.7 | 9.6 | - | - | - | (2.5) | 25.6 |
| - DAWN T-SERVICE | 71.5 | - | - | 48.0 | 6.9 | - | - | - | (1.8) | 18.4 |
| - WBT | - | - | - | - | - | - | - | - | - | - |
| RATE 200 | | | | | | | | | | |
| - SYSTEM SALES | 83.6 | (66.9) | - | 63.4 | 33.9 | 34.6 | - | - | (5.7) | 24.3 |
| - BUY/SELL | - | - | - | - | - | - | - | - | - | - |
| - T-SERVICE EXCL WBT | 2.0 | - | - | 0.9 | 0.5 | 0.5 | - | - | (0.1) | 0.3 |
| - DAWN T-SERVICE | 57.2 | - | - | 24.1 | 12.9 | 13.2 | - | - | (2.2) | 9.2 |
| - WBT | - | - | - | - | - | - | - | - | - | - |
| <u>Unbundled Services: (Billing based on CD)</u> | | | | | | | | | | |
| RATE 125 | (30.7) | - | - | - | - | - | - | - | (30.7) | - |
| RATE 300 | (0.2) | - | - | - | - | - | - | - | (0.2) | - |
| RATE 332 | (103.4) | - | - | - | - | - | - | - | (103.4) | - |
| | 23,139.8 | (3,792.2) | 0.0 | 5,171.3 | 2,686.7 | 5,205.4 | 15,069.8 | 0.0 | (3,187.2) | 1,985.9 |

ENBRIDGE GAS INC.
EGD RATE ZONE
UNIT RATE BY TYPE OF SERVICE*

| | COL. 1 | COL. 2 | COL. 3 | COL. 4 | COL. 5 | COL. 6 | COL. 7 | COL. 8 | COL. 9 | COL. 10 |
|--------------------------|---------------------|------------------|----------------|---------------------|---------|---------------------|---------|------------------------|--------------|---------------------------------|
| | TOTAL | SALES AND WBT | TOTAL SALES | TOTAL DELIVERIES | SPACE | DELIVE- RABILITY | DIRECT | NUMBER OF CUSTOMERS | RATE BASE | BUNDLED ANNUAL DELIVERIES |
| | (\$/m³) | (\$/m³) | (\$/m³) | (\$/m³) | (\$/m³) | (\$/m³) | (\$/m³) | (\$/m³) | (\$/m³) | (\$/m³) |
| Bundled Services: | | | | | | | | | | |
| RATE 1 | - SYSTEM SALES | 0.2086 | (0.0485) | 0.0000 | 0.0460 | 0.0271 | 0.0602 | 0.1502 | 0.0000 | (0.0440) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.2572 | 0.0000 | 0.0000 | 0.0460 | 0.0271 | 0.0602 | 0.1502 | 0.0000 | (0.0440) 0.0177 |
| | - DAWN T-SERVICE | 0.2572 | 0.0000 | 0.0000 | 0.0460 | 0.0271 | 0.0602 | 0.1502 | 0.0000 | (0.0440) 0.0177 |
| | - WESTERN T-SERVICE | 0.2086 | (0.0485) | 0.0000 | 0.0460 | 0.0271 | 0.0602 | 0.1502 | 0.0000 | (0.0440) 0.0177 |
| RATE 6 | - SYSTEM SALES | 0.2527 | (0.0485) | 0.0000 | 0.0460 | 0.0278 | 0.0510 | 0.1788 | 0.0000 | (0.0200) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.3013 | 0.0000 | 0.0000 | 0.0460 | 0.0278 | 0.0510 | 0.1788 | 0.0000 | (0.0200) 0.0177 |
| | - DAWN T-SERVICE | 0.3013 | 0.0000 | 0.0000 | 0.0460 | 0.0278 | 0.0510 | 0.1788 | 0.0000 | (0.0200) 0.0177 |
| | - WESTERN T-SERVICE | 0.2527 | (0.0485) | 0.0000 | 0.0460 | 0.0278 | 0.0510 | 0.1788 | 0.0000 | (0.0200) 0.0177 |
| RATE 9 | - SYSTEM SALES | 0.0151 | (0.0485) | 0.0000 | 0.0460 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - DAWN T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - WESTERN T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| RATE 100 | - SYSTEM SALES | 0.0675 | (0.0485) | 0.0000 | 0.0460 | 0.0213 | 0.0510 | 0.0000 | 0.0000 | (0.0200) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.1160 | 0.0000 | 0.0000 | 0.0460 | 0.0213 | 0.0510 | 0.0000 | 0.0000 | (0.0200) 0.0177 |
| | - DAWN T-SERVICE | 0.1160 | 0.0000 | 0.0000 | 0.0460 | 0.0213 | 0.0510 | 0.0000 | 0.0000 | (0.0200) 0.0177 |
| | - WESTERN T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| RATE 110 | - SYSTEM SALES | 0.0209 | (0.0485) | 0.0000 | 0.0460 | 0.0082 | 0.0011 | 0.0000 | 0.0000 | (0.0035) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0694 | 0.0000 | 0.0000 | 0.0460 | 0.0082 | 0.0011 | 0.0000 | 0.0000 | (0.0035) 0.0177 |
| | - DAWN T-SERVICE | 0.0694 | 0.0000 | 0.0000 | 0.0460 | 0.0082 | 0.0011 | 0.0000 | 0.0000 | (0.0035) 0.0177 |
| | - WESTERN T-SERVICE | 0.0209 | (0.0485) | 0.0000 | 0.0460 | 0.0082 | 0.0011 | 0.0000 | 0.0000 | (0.0035) 0.0177 |
| RATE 115 | - SYSTEM SALES | 0.0127 | (0.0485) | 0.0000 | 0.0460 | 0.0000 | 0.0012 | 0.0000 | 0.0000 | (0.0036) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0613 | 0.0000 | 0.0000 | 0.0460 | 0.0000 | 0.0012 | 0.0000 | 0.0000 | (0.0036) 0.0177 |
| | - DAWN T-SERVICE | 0.0613 | 0.0000 | 0.0000 | 0.0460 | 0.0000 | 0.0012 | 0.0000 | 0.0000 | (0.0036) 0.0177 |
| | - WESTERN T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| RATE 135 | - SYSTEM SALES | 0.0123 | (0.0485) | 0.0000 | 0.0460 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | (0.0028) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - DAWN T-SERVICE | 0.0609 | 0.0000 | 0.0000 | 0.0460 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | (0.0028) 0.0177 |
| | - WESTERN T-SERVICE | 0.0123 | (0.0485) | 0.0000 | 0.0460 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | (0.0028) 0.0177 |
| RATE 145 | - SYSTEM SALES | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - DAWN T-SERVICE | 0.0734 | 0.0000 | 0.0000 | 0.0460 | 0.0224 | 0.0000 | 0.0000 | 0.0000 | (0.0127) 0.0177 |
| | - WESTERN T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| RATE 170 | - SYSTEM SALES | 0.0200 | (0.0485) | 0.0000 | 0.0460 | 0.0066 | 0.0000 | 0.0000 | 0.0000 | (0.0017) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.0685 | 0.0000 | 0.0000 | 0.0460 | 0.0066 | 0.0000 | 0.0000 | 0.0000 | (0.0017) 0.0177 |
| | - DAWN T-SERVICE | 0.0685 | 0.0000 | 0.0000 | 0.0460 | 0.0066 | 0.0000 | 0.0000 | 0.0000 | (0.0017) 0.0177 |
| | - WESTERN T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| RATE 200 | - SYSTEM SALES | 0.0607 | (0.0485) | 0.0000 | 0.0460 | 0.0246 | 0.0251 | 0.0000 | 0.0000 | (0.0042) 0.0177 |
| | - BUY/SELL | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | - ONTARIO T-SERVICE | 0.1092 | 0.0000 | 0.0000 | 0.0460 | 0.0246 | 0.0251 | 0.0000 | 0.0000 | (0.0042) 0.0177 |
| | - DAWN T-SERVICE | 0.1092 | 0.0000 | 0.0000 | 0.0460 | 0.0246 | 0.0251 | 0.0000 | 0.0000 | (0.0042) 0.0177 |
| | - WESTERN T-SERVICE | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |

Unbundled Services (Billing based on CD, \$/m3):

| | | | | | | | | | | |
|-----------------|------------------------|----------|--------|--------|--------|--------|--------|--------|--------|-----------------|
| RATE 125 | - All | (0.3318) | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | (0.3318) 0.0000 |
| | - Customer-specific ** | | | | | | | | | |
| RATE 300 | - All | (1.5672) | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | (1.5672) 0.0000 |
| | - Customer-specific ** | | | | | | | | | |
| RATE 332 | - All | (0.3320) | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | (0.3320) 0.0000 |

Notes:

* Unit Rates derived based on 2021 actual volumes

ENBRIDGE GAS INC.
EGD RATE ZONE
2021 DEFERRAL AND VARIANCE ACCOUNT CLEARING
BILL ADJUSTMENT IN JANUARY 2023 FOR TYPICAL CUSTOMERS

| ITEM NO. | <u>COL. 1</u> | <u>COL. 2</u> | <u>COL. 3</u> | <u>COL. 4</u> | <u>COL. 5</u> | <u>COL. 6</u> | <u>COL. 7</u> | <u>COL. 8</u> | <u>COL. 9</u> | <u>COL. 10</u> |
|----------|---------------------------------|--|-------------------------------------|--|---------------------------------------|--|--------------------------------|-------------------------------------|----------------------------------|-------------------------------------|
| | | | <u>UNIT RATE</u> | | | | <u>BILL ADJUSTMENT</u> | | | |
| | <u>GENERAL SERVICE</u> | <u>ANNUAL VOLUME</u> m ³ | <u>SALES</u> (c/m ³) | <u>ONTARIO TS</u> (c/m ³) | <u>DAWN TS</u> (c/m ³) | <u>WESTERN TS</u> (c/m ³) | <u>SALES CUSTOMERS</u> (\$) | <u>ONTARIO TS CUSTOMERS</u> (\$) | <u>DAWN TS CUSTOMERS</u> (\$) | <u>WESTERN TS CUSTOMERS</u> (\$) |
| 1.1 | RATE 1 RESIDENTIAL | | | | | | | | | |
| 1.2 | Heating & Water Heating | 2,400 | 0.2086 | 0.2572 | 0.2572 | 0.2086 | 5.01 | 6.17 | 6.17 | 5.01 |
| 2.1 | RATE 6 COMMERCIAL | | | | | | | | | |
| 2.2 | Heating & Other Uses | 22,606 | 0.2527 | 0.3013 | 0.3013 | 0.2527 | 57.14 | 68.10 | 68.10 | 57.14 |
| 2.3 | General Use | 43,285 | 0.2527 | 0.3013 | 0.3013 | 0.2527 | 109.40 | 130.40 | 130.40 | 109.40 |
| | <u>CONTRACT SERVICE</u> | | | | | | | | | |
| 3.1 | RATE 100 | | | | | | | | | |
| 3.2 | Industrial - small size | 339,188 | 0.0675 | 0.1160 | 0.1160 | 0.0000 | 228.93 | 393.51 | 393.51 | - |
| 4.1 | RATE 110 | | | | | | | | | |
| 4.2 | Industrial - small size, 50% LF | 598,568 | 0.0209 | 0.0694 | 0.0694 | 0.0209 | 125.09 | 415.53 | 415.53 | 125.09 |
| 4.3 | Industrial - avg. size, 75% LF | 9,976,121 | 0.0209 | 0.0694 | 0.0694 | 0.0209 | 2,084.82 | 6,925.45 | 6,925.45 | 2,084.82 |
| 5.1 | RATE 115 | | | | | | | | | |
| 5.2 | Industrial - small size, 80% LF | 4,471,609 | 0.0127 | 0.0613 | 0.0613 | 0.0000 | 570.01 | 2,739.73 | 2,739.73 | - |
| 6.1 | RATE 135 | | | | | | | | | |
| 6.2 | Industrial - Seasonal Firm | 598,567 | 0.0123 | 0.0000 | 0.0609 | 0.0123 | 73.83 | - | 364.26 | 73.83 |
| 7.1 | RATE 145 | | | | | | | | | |
| 7.2 | Commercial - avg. size | 598,568 | 0.0000 | 0.0000 | 0.0734 | 0.0000 | - | - | 439.29 | - |
| 8.1 | RATE 170 | | | | | | | | | |
| 8.2 | Industrial - avg. size, 75% LF | 9,976,121 | 0.0200 | 0.0685 | 0.0685 | 0.0000 | 1,996.70 | 6,837.33 | 6,837.33 | - |

Notes:

Col. 7 = Col. 2 x Col. 3

Col. 8 = Col. 2 x Col. 4

Col. 9 = Col. 2 x Col. 5

Col. 10 = Col. 2 x Col. 6

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rate and Type of Service
2021 Deferral Account Disposition

| Line No. | Particulars | <u>Sales/System Gas</u> <u>Unit Rate for Billing</u> | <u>Bundled T-Service</u> <u>Unit Rate for Billing</u> | <u>T-Service</u> <u>Unit Rate for Billing</u> |
|-------------|-------------------------|---|--|--|
| | | Unit Rate (cents/m ³) (a) | Unit Rate (cents/m ³) (b) | Unit Rate (cents/m ³) (c) |
| | <u>Union North West</u> | | | |
| 1 | Rate 01 | (0.7877) | (0.7877) | 0.4169 |
| 2 | Rate 10 | 0.3313 | 0.3313 | 1.1667 |
| 3 | Rate 20 | (4.9363) | (4.9363) | (0.0106) |
| 4 | Rate 25 | 0.1585 | 0.1585 | (0.0167) |
| 5 | Rate 100 | (0.0159) | (0.0159) | (0.0159) |
| | <u>Union North East</u> | | | |
| 6 | Rate 01 | 0.3537 | 0.3537 | 0.4169 |
| 7 | Rate 10 | 1.1092 | 1.1092 | 1.1667 |
| 8 | Rate 20 | (0.9102) | (0.9102) | (0.0106) |
| 9 | Rate 25 | (0.0549) | (0.0549) | (0.0167) |
| 10 | Rate 100 | (0.0159) | (0.0159) | (0.0159) |
| | <u>Union South</u> | | | |
| 11 | Rate M1 | 0.7547 | 0.4169 | - |
| 12 | Rate M2 | 1.5045 | 1.1667 | - |
| 13 | Rate M4 | 0.4193 | 0.0815 | - |
| 14 | Rate M5 | 0.2270 | (0.1108) | - |
| 15 | Rate M7 | 0.4564 | 0.1186 | - |
| 16 | Rate M9 | 0.4673 | 0.1295 | - |
| 17 | Rate M10 | 0.3250 | (0.0128) | - |
| 18 | Rate T1 | - | - | 0.0202 |
| 19 | Rate T2 | - | - | 0.0420 |
| 20 | Rate T3 | - | - | 0.0958 |

ENBRIDGE GAS INC.
Union Rate Zones
2021 Deferral Account Balances To Be Cleared
Year Ending December 31, 2021

| Line No. | Account Number | Account Name (\$000's) | Balance (a) | Interest (b) | Total (c) |
|----------|--|---|----------------|-----------------|----------------|
| 1 | 179-131 | Upstream Transportation Optimization | 8,616 | 78 | 8,695 |
| 2 | 179-107 | Spot Gas Variance Account | - | - | - |
| 3 | 179-108 | Unabsorbed Demand Costs Variance Account | (1,666) | (28) | (1,694) |
| 4 | 179-153 | Base Service North T-Service TransCanada Capacity | 84 | 1 | 84 |
| 5 | 179-070 | Short-Term Storage and Other Balancing Services | 3,577 | 32 | 3,609 |
| 6 | 179-133 | Normalized Average Consumption | 18,997 | 239 | 19,237 |
| 7 | 179-132 | Deferral Clearing Variance Account | (3,120) | (45) | (3,166) |
| 8 | 179-151 | OEB Cost Assessment Variance Account | 907 | 11 | 919 |
| 9 | 179-103 | Unbundled Services Unauthorized Storage Overrun | - | - | - |
| 10 | 179-112 | Gas Distribution Access Rule Costs | - | - | - |
| 11 | 179-123 | Conservation Demand Management | - | - | - |
| 12 | 179-136 | Parkway West Project Costs | (603) | (6) | (610) |
| 13 | 179-137 | Brantford-Kirkwall/Parkway D Project Costs | (45) | (0) | (45) |
| 14 | 179-142 | Lobo C Compressor/Hamilton-Milton Pipeline Project Costs | 24 | 0 | 24 |
| 15 | 179-144 | Lobo D/Bright C/Dawn H Compressor Project Costs | (112) | (4) | (116) |
| 16 | 179-149 | Burlington-Oakville Project Costs | (51) | (1) | (52) |
| 17 | 179-156 | Panhandle Reinforcement Project Costs | (3,162) | (36) | (3,198) |
| 18 | 179-162 | Sudbury Replacement Project | - | - | - |
| 19 | 179-138 | Parkway Obligation Rate Variance | - | - | - |
| 20 | 179-143 | Unauthorized Overrun Non-Compliance Account | - | - | - |
| 21 | 179-157 | Pension and OPEB Forecast Accrual vs. Actual Cash Payment Differential V/A | - | (1,346) | (1,346) |
| 22 | 179-135 | Unaccounted for Gas Volume Variance Account | 20,501 | 177 | 20,678 |
| 23 | 179-141 | Unaccounted for Gas Price Variance Account | 3,358 | 32 | 3,390 |
| 24 | Total for Union Rate Zone Specific Accounts (Lines 1 through 23) | | <u>47,305</u> | <u>(895)</u> | <u>46,411</u> |
| 25 | 179-382 | Earnings Sharing (Union Rate Zone Portion) | - | - | - |
| 26 | 179-383 | Tax Variance - Accelerated CCA - (Union Rate Zone Portion) | (9,047) | (107) | (9,154) |
| 27 | 179-385 | IRP Operating Costs Deferral Account - (Union Rate Zone Portion) | 27 | 0 | 27 |
| 28 | 179-386 | IRP Capital Costs Deferral Account | - | - | - |
| 29 | 179-380 | Expansion of Natural Gas Distribution Systems V/A (Union Rate Zone Portion) | - | - | - |
| 30 | Total for EGI Accounts allocated to Union Rate Zone | | <u>(9,020)</u> | <u>(107)</u> | <u>(9,127)</u> |
| 31 | Total Union Rate Zone Deferral Account Balances (Line 24 + Line 30) | | <u>38,286</u> | <u>(1,002)</u> | <u>37,284</u> |

ENBRIDGE GAS INC.
Union Rate Zones
Classification and Allocation of Deferral and Variance Account Balances

| Line No. | Particulars (\$000's) | Acct No. | Union North | | | | | Union South | | | | | | | | | | | | | Excess Utility | | | Total | | |
|--------------------------------------|--|----------|-------------|---------|---------|----------|---------|-------------|-------|-------|-------|------|-----|-----|-------|---------|------|---------|-----|------|----------------|------|-----|---------|-------|-----|
| | | | Rate 01 | Rate 10 | Rate 20 | Rate 100 | Rate 25 | M1 | M2 | M4 | M5A | M7 | M9 | M10 | T1 | T2 | T3 | M12 | M13 | C1 | M16 | M17 | | | | |
| | | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) | | (v) | (w) |
| <u>Gas Supply Related Deferrals:</u> | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 | Upstream Transportation Optimization | 179-131 | 320 | 44 | 21 | - | 92 | 6,665 | 1,287 | 138 | 10 | 78 | 39 | 1 | - | - | - | - | - | - | - | - | - | - | 8,695 | |
| 2 | Spot Gas Variance Account | 179-107 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 3 | Unabsorbed Demand Cost (UDC) Variance Account | 179-108 | (3,908) | (762) | (168) | - | - | 2,551 | 492 | 53 | 4 | 30 | 15 | 0 | - | - | - | - | - | - | - | - | - | (1,694) | | |
| 4 | Base Service North T-Service TransCanada Capacity Account | 179-153 | - | - | 57 | 28 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 84 | | |
| 5 | Total Gas Supply Related Deferrals | | (3,588) | (718) | (90) | 28 | 92 | 9,215 | 1,779 | 190 | 14 | 108 | 54 | 1 | - | - | - | - | - | - | - | - | - | 7,085 | | |
| <u>Storage Related Deferrals:</u> | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 6 | Short-Term Storage and Other Balancing Services | 179-70 | 493 | 139 | 76 | 2 | - | 1,124 | 424 | 190 | 2 | 106 | 20 | 0 | 81 | 859 | 92 | - | - | - | - | - | - | 3,609 | | |
| <u>Delivery Related Deferrals:</u> | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 7 | Normalized Average Consumption (NAC) | 179-133 | 5,330 | 3,797 | - | - | - | 4,629 | 5,481 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19,237 | | |
| 8 | Deferral Clearing Variance Account - Delivery | 179-132 | (571) | (191) | 4 | 6 | 1 | (1,777) | (683) | 4 | 0 | 5 | 1 | 0 | 3 | 31 | 2 | - | - | - | - | - | - | (3,166) | | |
| 9 | OEB Cost Assessment Variance Account | 179-151 | 184 | 16 | 14 | 12 | 6 | 464 | 43 | 16 | 18 | 5 | 1 | 0 | 12 | 33 | 4 | 86 | 0 | 3 | 2 | 0 | - | 919 | | |
| 10 | Unbundled Services Unauthorized Storage Overrun | 179-103 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 11 | Gas Distribution Access Rule (GDAR) Costs | 179-112 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 12 | Conservation Demand Management | 179-123 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 13 | Parkway West Project Costs | 179-136 | 4 | (8) | (1) | 2 | 1 | 103 | 4 | 3 | 3 | 0 | (0) | 0 | 4 | 19 | (1) | (748) | 0 | 1 | 3 | 0 | - | (610) | | |
| 14 | Brantford-Kirkwall/Parkway D Project Costs | 179-137 | (7) | (1) | (1) | (1) | (0) | (16) | (3) | (1) | (1) | (0) | (0) | (0) | (1) | (2) | (0) | (11) | (0) | (0) | (0) | (0) | - | (45) | | |
| 15 | Lobo C Compressor/Hamilton-Milton Pipeline Project Costs | 179-142 | (40) | (2) | (4) | (4) | (2) | (150) | (20) | (7) | (5) | (2) | (0) | (0) | (6) | (30) | (2) | 298 | (0) | (1) | (1) | (0) | - | 24 | | |
| 16 | Lobo D/Bright C/ Dawn H Compressor Project Costs | 179-144 | (108) | (4) | (6) | (7) | (3) | (368) | (39) | (15) | (13) | (4) | (0) | (0) | (15) | (73) | (3) | 559 | (0) | (7) | (8) | (1) | - | (116) | | |
| 17 | Burlington-Oakville Project Costs | 179-149 | (3) | (1) | (0) | (0) | (0) | (25) | (8) | (2) | (0) | (1) | (0) | (0) | (2) | (13) | (2) | 6 | 0 | (0) | 0 | 0 | - | (52) | | |
| 18 | Parhandle Reinforcement Project Costs | 179-156 | (31) | (5) | (4) | (3) | (1) | (696) | (236) | (255) | (6) | (56) | (0) | (0) | (169) | (1,240) | (1) | (33) | (0) | (0) | (381) | (80) | - | (3,198) | | |
| 19 | Sudbury Replacement Project | 179-162 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 20 | Parkway Obligation Rate Variance | 179-138 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 21 | Unauthorized Overrun Non-Compliance Account | 179-143 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 22 | Pension & OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account | 179-157 | (270) | (25) | (24) | (20) | (10) | (662) | (64) | (27) | (31) | (7) | (1) | (0) | (18) | (47) | (5) | (127) | (0) | (4) | (3) | (0) | - | (1,346) | | |
| 23 | Unaccounted for Gas (UFG) Volume Variance Account | 179-135 | 328 | 109 | 50 | - | 21 | 2,178 | 837 | 459 | 48 | 516 | 68 | 0 | 295 | 2,848 | 202 | 9,393 | 23 | - | 3,131 | 162 | 10 | 20,678 | | |
| 24 | Unaccounted for Gas (UFG) Price Variance Account | 179-141 | 190 | 63 | 29 | - | 12 | 1,260 | 484 | 266 | 28 | 298 | 39 | 0 | - | - | - | - | 13 | - | 687 | 21 | - | 3,390 | | |
| 25 | Tax Variance - Accelerated CCA - EGI | 179-383 | (1,627) | (251) | (178) | (137) | (49) | (3,553) | (538) | (134) | (114) | (47) | (9) | (0) | (93) | (410) | (54) | (1,888) | (1) | (53) | (17) | (2) | - | (9,154) | | |
| 26 | IRP Operating Costs Deferral Account - EGI | 179-385 | 5 | 1 | 1 | 0 | 0 | 11 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 6 | 0 | 0 | 0 | 0 | - | 27 | | |
| 27 | IRP Operating Costs Deferral Account - EGI | 179-386 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 28 | Total Delivery-Related Deferrals | | 3,384 | 3,498 | (120) | (152) | (24) | 1,397 | 5,262 | 308 | (72) | 708 | 97 | (0) | 10 | 1,117 | 139 | 7,541 | 35 | (61) | 3,414 | 100 | 10 | 26,590 | | |
| 29 | Total 2021 Storage and Delivery Disposition (Line 6 + Line 28) | | 3,877 | 3,638 | (45) | (150) | (24) | 2,522 | 5,686 | 498 | (70) | 814 | 117 | (0) | 91 | 1,977 | 231 | 7,541 | 35 | (61) | 3,414 | 100 | 10 | 30,199 | | |
| 30 | Total 2021 Deferral Account Disposition (Line 5 + Line 29) | | 288 | 2,920 | (134) | (122) | 68 | 11,737 | 7,465 | 688 | (57) | 922 | 170 | 1 | 91 | 1,977 | 231 | 7,541 | 35 | (61) | 3,414 | 100 | 10 | 37,284 | | |
| 31 | Earnings Sharing Deferral Account - EGI | 179-382 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 32 | Grand Total (Line 30 + Line 31) | | 288 | 2,920 | (134) | (122) | 68 | 11,737 | 7,465 | 688 | (57) | 922 | 170 | 1 | 91 | 1,977 | 231 | 7,541 | 35 | (61) | 3,414 | 100 | 10 | 37,284 | | |

ENBRIDGE GAS INC.Union Rate ZonesAllocation of 2021 Gas Supply Related Deferral Accounts by Union North East and Union North West

| Line No. | Particulars (\$000's) | Acct No. | Rate 01 | Rate 10 | Rate 20 | Rate 100 | Rate 25 | Total |
|--------------------------------------|---|----------|---------|---------|---------|----------|---------|-----------------|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) = (sum b:f) |
| <u>Union North West</u> | | | | | | | | |
| <u>Gas Supply Related Deferrals:</u> | | | | | | | | |
| 1 | Spot Gas Variance Account | 179-107 | - | - | - | - | - | - |
| 2 | Unabsorbed Demand Cost (UDC) Variance Account | 179-108 | (3,883) | (756) | (167) | - | - | (4,806) |
| 3 | Upstream Transportation Optimization | 179-131 | 716 | 175 | 80 | - | 100 | 1,072 |
| 4 | Total Gas Supply Related Deferrals | | (3,167) | (581) | (87) | - | 100 | (3,735) |
| <u>Storage Related Deferrals:</u> | | | | | | | | |
| 5 | Short-Term Storage and Other Balancing Services (1) | 179-70 | 141 | 35 | 7 | - | - | 183 |
| 6 | Total North West Deferral Account Disposition (Line 6 + Line 7) | | (3,026) | (546) | (80) | - | 100 | (3,552) |
| <u>Union North East</u> | | | | | | | | |
| <u>Gas Supply Related Deferrals:</u> | | | | | | | | |
| 7 | Spot Gas Variance Account | 179-107 | - | - | - | - | - | - |
| 8 | Unabsorbed Demand Cost (UDC) Variance Account | 179-108 | (25) | (6) | (1) | - | - | (32) |
| 9 | Upstream Transportation Optimization | 179-131 | (396) | (131) | (59) | - | (8) | (594) |
| 10 | Total Gas Supply Related Deferrals | | (421) | (137) | (60) | - | (8) | (626) |
| <u>Storage Related Deferrals:</u> | | | | | | | | |
| 11 | Short-Term Storage and Other Balancing Services (1) | 179-70 | 352 | 104 | 46 | - | - | 502 |
| 12 | Total North East Deferral Account Disposition (Line 14 + Line 15) | | (69) | (33) | (14) | - | (8) | (124) |
| <u>Total North</u> | | | | | | | | |
| <u>Gas Supply Related Deferrals:</u> | | | | | | | | |
| 13 | Spot Gas Variance Account | 179-107 | - | - | - | - | - | - |
| 14 | Unabsorbed Demand Cost (UDC) Variance Account | 179-108 | (3,908) | (762) | (168) | - | - | (4,839) |
| 15 | Upstream Transportation Optimization | 179-131 | 320 | 44 | 21 | - | 92 | 478 |
| 16 | Total North Gas Supply Related Deferrals | | (3,588) | (718) | (147) | - | 92 | (4,361) |
| <u>Storage Related Deferrals:</u> | | | | | | | | |
| 17 | Short-Term Storage and Other Balancing Services (1) | 179-70 | 493 | 139 | 53 | - | - | 685 |
| 18 | Total North Deferral Account Disposition (Line 22 + Line 23) | | (3,095) | (579) | (94) | - | 92 | (3,676) |

Notes:

(1) Excludes allocation to Rate 20/100 bundled storage service.

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for One-Time Adjustment - Delivery
2021 Deferral Account Disposition

| Line No. | Particulars | Rate Class | 2021 Deferral Balances (\$000's) (a) | 2021 Earnings Sharing Mechanism (\$000's) (b) | Deferral Balance for Disposition (\$000's) (c) = (a + b) | 2021 Actual Volume (10 ³ m ³) (d) | Unit Rate (cents/m ³) (e) = (c / d) * 100 |
|-------------|--------------------------------|---------------|--|--|---|--|---|
| | <u>Union North</u> | | | | | | |
| 1 | Small Volume General Service | 01 | 3,877 | - | 3,877 | 929,941 | 0.4169 |
| 2 | Large Volume General Service | 10 | 3,638 | - | 3,638 | 311,794 | 1.1667 |
| 3 | Medium Volume Firm Service | 20 | (68) | - | (68) | 637,600 | (0.0106) |
| 4 | Large Volume High Load Factor | 100 | (152) | - | (152) | 958,587 | (0.0159) |
| 5 | Large Volume Interruptible | 25 | (24) | - | (24) | 143,898 | (0.0167) |
| | <u>Union South</u> | | | | | | |
| 6 | Small Volume General Service | M1 | 2,522 | - | 2,522 | 2,897,087 | 0.0870 |
| 7 | Large Volume General Service | M2 | 5,686 | - | 5,686 | 1,113,864 | 0.5105 |
| 8 | Firm Com/Ind Contract | M4 | 498 | - | 498 | 610,808 | 0.0815 |
| 9 | Interruptible Com/Ind Contract | M5 | (70) | - | (70) | 63,511 | (0.1108) |
| 10 | Special Large Volume Contract | M7 | 814 | - | 814 | 686,353 | 0.1186 |
| 11 | Large Wholesale | M9 | 117 | - | 117 | 90,096 | 0.1295 |
| 12 | Small Wholesale | M10 | (0) | - | (0) | 320 | (0.0128) |
| 13 | Contract Carriage Service | T1 | 91 | - | 91 | 453,007 | 0.0202 |
| 14 | Contract Carriage Service | T2 | 1,977 | - | 1,977 | 4,700,474 | 0.0420 |
| 15 | Contract Carriage- Wholesale | T3 | 231 | - | 231 | 241,187 | 0.0958 |

ENBRIDGE GAS INC.
 Union Rate Zones
 Unit Rates for One-Time Adjustment - Gas Supply Commodity
2021 Deferral Account Disposition

| Line | | Rate | 2021 | 2021 | Deferral | 2021 | Unit Rate |
|------|--------------------------------|-------|-----------|-----------|---------------|-----------------------------------|-------------------------|
| No. | Particulars | Class | Deferral | Earnings | Balance | Actual | (cents/m ³) |
| | | | Balances | Sharing | for | Volume | |
| | | | (\$000's) | Mechanism | Disposition | (10 ³ m ³) | |
| | | | (a) | (b) | (c) = (a + b) | (d) | (e) = (c / d) * 100 |
| 1 | Small Volume General Service | M1 | 9,215 | - | 9,215 | 2,728,007 | 0.3378 |
| 2 | Large Volume General Service | M2 | 1,779 | - | 1,779 | 526,743 | 0.3378 |
| 3 | Firm Com/Ind Contract | M4 | 190 | - | 190 | 56,304 | 0.3378 |
| 4 | Interruptible Com/Ind Contract | M5 | 14 | - | 14 | 4,043 | 0.3378 |
| 5 | Special Large Volume Contract | M7 | 108 | - | 108 | 31,987 | 0.3378 |
| 6 | Large Wholesale | M9 | 54 | - | 54 | 15,903 | 0.3378 |
| 7 | Small Wholesale | M10 | 1 | - | 1 | 320 | 0.3378 |

ENBRIDGE GAS INC.

Union Rate Zones

Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage

2021 Deferral Account Disposition

| Line No. | Particulars | Rate Class | 2021 Deferral Balances (\$000's) (a) | 2021 Earnings Sharing Mechanism (\$000's) (b) | Deferral Balance for Disposition (\$000's) (c) = (a + b) | 2021 Actual Volume/ Demand (d) | Billing Units | Unit Volumetric/ Demand Rate (cents/m ³) (e) = (c / d) * 100 |
|--|---|------------|---|--|---|-----------------------------------|-----------------------------------|---|
| <u>Gas Supply Transportation Charges</u> | | | | | | | | |
| <u>Union North West</u> | | | | | | | | |
| 1 | Small Volume General Service | 01 | (3,167) | - | (3,167) | 262,912 | 10 ³ m ³ | (1.2045) |
| 2 | Large Volume General Service | 10 | (581) | - | (581) | 69,572 | 10 ³ m ³ | (0.8354) |
| 3 | Medium Volume Firm Service | 20 | (87) | - | (87) | 1,764 | 10 ³ m ³ /d | (4.9257) |
| 4 | Large Volume Interruptible | 25 | 100 | - | 100 | 57,362 | 10 ³ m ³ | 0.1752 |
| <u>Union North East</u> | | | | | | | | |
| 5 | Small Volume General Service | 01 | (421) | - | (421) | 667,029 | 10 ³ m ³ | (0.0632) |
| 6 | Large Volume General Service | 10 | (137) | - | (137) | 238,396 | 10 ³ m ³ | (0.0575) |
| 7 | Medium Volume Firm Service | 20 | (60) | - | (60) | 6,630 | 10 ³ m ³ /d | (0.8996) |
| 8 | Large Volume Interruptible | 25 | (8) | - | (8) | 21,827 | 10 ³ m ³ | (0.0382) |
| 9 | North T-Service Transportation from Dawn Base Service (\$/GJ) | 20T/100T | 84 | - | 84 | 264,264 | GJ/d | 0.320 |
| <u>Storage (\$/GJ)</u> | | | | | | | | |
| 10 | Bundled-T Storage Service | 20T/100T | 25 | - | 25 | 141,504 | GJ/d | 0.179 |

ENBRIDGE GAS INC.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition
2021 Deferral Account Disposition

| Line No. | Particulars (\$000's) (1) | Rate Class | 2021 Deferral Balances (a) | 2021 Earnings Sharing Mechanism (b) | Deferral Balance for Disposition (c) = (a + b) |
|-------------|--|---------------|-------------------------------------|---|--|
| 1 | Transportation | M12 | 7,541 | - | 7,541 |
| 2 | Transportation of Locally Produced Gas | M13 | 35 | - | 35 |
| 3 | Cross Franchise Transportation | C1 | 3,414 | - | 3,414 |
| 4 | Storage and Transportation Services | M16 | 100 | - | 100 |
| 5 | Transporation Service | M17 | 10 | - | 10 |

Notes:

(1)

Ex-franchise customer specific amounts determined using approved deferral account allocation methodologies.

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical General Service Customers

| Line No. | Particulars | Deferral Unit Rate (cents/m ³) (a) | Volume (m ³) (1) (b) | Bill Impact (\$) (c) = (a x b) / 100 |
|-------------------------------------|------------------------------------|--|----------------------------------|--------------------------------------|
| <u>Small Volume General Service</u> | | | | |
| <u>Rate M1 - Union South</u> | | | | |
| 1 | Delivery | 0.0870 | 2,200 | 1.91 |
| 2 | Commodity | 0.3378 | 2,200 | 7.43 |
| 3 | Sales Service Impact | 0.4248 | | 9.34 |
| 4 | Direct Purchase Impact | | | 1.91 |
| <u>Rate 01 - Union North West</u> | | | | |
| 5 | Delivery | 0.4169 | 2,200 | 9.17 |
| 6 | Commodity | - | 2,200 | - |
| 7 | Transportation | (1.2045) | 2,200 | (26.50) |
| 8 | Sales Service Impact | (0.7877) | | (17.33) |
| 9 | Bundled-T (Direct Purchase) Impact | | | (17.33) |
| <u>Rate 01 - Union North East</u> | | | | |
| 10 | Delivery | 0.4169 | 2,200 | 9.17 |
| 11 | Commodity | - | 2,200 | - |
| 12 | Transportation | (0.0632) | 2,200 | (1.39) |
| 13 | Sales Service Impact | 0.3537 | | 7.78 |
| 14 | Bundled-T (Direct Purchase) Impact | | | 7.78 |
| <u>Large Volume General Service</u> | | | | |
| <u>Rate M2 - Union South</u> | | | | |
| 15 | Delivery | 0.5105 | 73,000 | 372.65 |
| 16 | Commodity | 0.3378 | 73,000 | 246.60 |
| 17 | Sales Service Impact | 0.8483 | | 619.25 |
| 18 | Direct Purchase Impact | | | 372.65 |
| <u>Rate 10 - Union North West</u> | | | | |
| 19 | Delivery | 1.1667 | 93,000 | 1,085.06 |
| 20 | Commodity | - | 93,000 | - |
| 21 | Transportation | (0.8354) | 93,000 | (776.97) |
| 22 | Sales Service Impact | 0.3313 | | 308.09 |
| 23 | Bundled-T (Direct Purchase) Impact | | | 308.09 |
| <u>Rate 10 - Union North East</u> | | | | |
| 24 | Delivery | 1.1667 | 93,000 | 1,085.06 |
| 25 | Commodity | - | 93,000 | - |
| 26 | Transportation | (0.0575) | 93,000 | (53.46) |
| 27 | Sales Service Impact | 1.1092 | | 1,031.60 |
| 28 | Bundled-T (Direct Purchase) Impact | | | 1,031.60 |

Notes:

(1) Average consumption, per customer, for the period January 1, 2021 to December 31, 2021.

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

| Line No. | Particulars | Deferral Unit Rate (cents/m ³) (a) | Billing Units (m ³) (b) | Bill Impact (\$ (1)) (c) |
|---|------------------------------------|--|---|--------------------------------|
| <u>Union North</u> | | | | |
| <u>Small Rate 20 - Union North West</u> | | | | |
| 1 | Delivery | (0.0106) | 3,000,000 | (318) |
| 2 | Transportation | (4.9257) | 14,000 | (8,275) |
| 3 | Sales Service Impact | (4.9363) | | (8,593) |
| 4 | Bundled-T (Direct Purchase) Impact | | | (8,593) |
| <u>Large Rate 20 - Union North West</u> | | | | |
| 5 | Delivery | (0.0106) | 15,000,000 | (1,590) |
| 6 | Transportation | (4.9257) | 60,000 | (35,465) |
| 7 | Sales Service Impact | (4.9363) | | (37,055) |
| 8 | Bundled-T (Direct Purchase) Impact | | | (37,055) |
| <u>Small Rate 20 - Union North East</u> | | | | |
| 9 | Delivery | (0.0106) | 3,000,000 | (318) |
| 10 | Transportation | (0.8996) | 14,000 | (1,511) |
| 11 | Sales Service Impact | (0.9102) | | (1,829) |
| 12 | Bundled-T (Direct Purchase) Impact | | | (1,829) |
| <u>Large Rate 20 - Union North East</u> | | | | |
| 13 | Delivery | (0.0106) | 15,000,000 | (1,590) |
| 14 | Transportation | (0.8996) | 60,000 | (6,477) |
| 15 | Sales Service Impact | (0.9102) | | (8,067) |
| 16 | Bundled-T (Direct Purchase) Impact | | | (8,067) |
| <u>Average Rate 25 - Union North West</u> | | | | |
| 17 | Delivery | (0.0167) | 2,275,000 | (380) |
| 18 | Transportation | 0.1752 | 2,275,000 | 3,985 |
| 19 | Sales Service Impact | 0.1585 | | 3,605 |
| 20 | Bundled-T (Direct Purchase) Impact | | | 3,605 |
| <u>Average Rate 25 - Union North East</u> | | | | |
| 21 | Delivery | (0.0167) | 2,275,000 | (380) |
| 22 | Transportation | (0.0382) | 2,275,000 | (869) |
| 23 | Sales Service Impact | (0.0549) | | (1,249) |
| 24 | Bundled-T (Direct Purchase) Impact | | | (1,249) |
| <u>Small Rate 100</u> | | | | |
| 25 | T-Service (Direct Purchase) Impact | (0.0159) | 27,000,000 | (4,286) |
| <u>Large Rate 100</u> | | | | |
| 26 | T-Service (Direct Purchase) Impact | (0.0159) | 240,000,000 | (38,094) |
| <u>Union South</u> | | | | |
| <u>Small Rate M4</u> | | | | |
| 27 | Delivery | 0.0815 | 875,000 | 713 |
| 28 | Commodity | 0.3378 | 875,000 | 2,956 |
| 29 | Sales Service Impact | 0.4193 | | 3,669 |
| 30 | Direct Purchase Impact | | | 713 |
| <u>Large Rate M4</u> | | | | |
| 31 | Delivery | 0.0815 | 12,000,000 | 9,779 |
| 32 | Commodity | 0.3378 | 12,000,000 | 40,536 |
| 33 | Sales Service Impact | 0.4193 | | 50,315 |
| 34 | Direct Purchase Impact | | | 9,779 |

Notes:

(1) Transportation bill impacts based on monthly demand (m³/d).

ENBRIDGE GAS INC.
Union Rate Zones
Calculation of One-Time Adjustments for Typical Small and Large Customers

| Line No. | Particulars | Deferral Unit Rate (cents/m ³) (b) | Billing Units (m ³) (c) | Bill Impact (\$)(1) (d) |
|------------------------------------|------------------------|--|---|-------------------------------|
| <u>Union South (continued)</u> | | | | |
| <u>Small Rate M5 Interruptible</u> | | | | |
| 1 | Delivery | (0.1108) | 825,000 | (914) |
| 2 | Commodity | 0.3378 | 825,000 | 2,787 |
| 3 | Sales Service Impact | 0.2270 | | 1,873 |
| 4 | Direct Purchase Impact | | | (914) |
| <u>Large Rate M5 Interruptible</u> | | | | |
| 5 | Delivery | (0.1108) | 6,500,000 | (7,200) |
| 6 | Commodity | 0.3378 | 6,500,000 | 21,957 |
| 7 | Sales Service Impact | 0.2270 | | 14,757 |
| 8 | Direct Purchase Impact | | | (7,200) |
| <u>Small Rate M7</u> | | | | |
| 9 | Delivery | 0.1186 | 36,000,000 | 42,695 |
| 10 | Commodity | 0.3378 | 36,000,000 | 121,609 |
| 11 | Sales Service Impact | 0.4564 | | 164,304 |
| 12 | Direct Purchase Impact | | | 42,695 |
| <u>Large Rate M7</u> | | | | |
| 13 | Delivery | 0.1186 | 52,000,000 | 61,671 |
| 14 | Commodity | 0.3378 | 52,000,000 | 175,658 |
| 15 | Sales Service Impact | 0.4564 | | 237,329 |
| 16 | Direct Purchase Impact | | | 61,671 |
| <u>Small Rate M9</u> | | | | |
| 17 | Delivery | 0.1295 | 6,950,000 | 9,002 |
| 18 | Commodity | 0.3378 | 6,950,000 | 23,477 |
| 19 | Sales Service Impact | 0.4673 | | 32,480 |
| 20 | Direct Purchase Impact | | | 9,002 |
| <u>Large Rate M9</u> | | | | |
| 21 | Delivery | 0.1295 | 20,178,000 | 26,136 |
| 22 | Commodity | 0.3378 | 20,178,000 | 68,162 |
| 23 | Sales Service Impact | 0.4673 | | 94,298 |
| 24 | Direct Purchase Impact | | | 26,136 |
| <u>Rate M10</u> | | | | |
| 25 | Delivery | (0.0128) | 94,500 | (12) |
| 26 | Commodity | 0.3378 | 94,500 | 319 |
| 27 | Sales Service Impact | 0.3250 | | 307 |
| 28 | Direct Purchase Impact | | | (12) |
| <u>Small Rate T1</u> | | | | |
| 29 | Direct Purchase Impact | 0.0202 | 7,537,000 | 1,521 |
| <u>Average Rate T1</u> | | | | |
| 30 | Direct Purchase Impact | 0.0202 | 11,565,938 | 2,334 |
| <u>Large Rate T1</u> | | | | |
| 31 | Direct Purchase Impact | 0.0202 | 25,624,080 | 5,171 |
| <u>Small Rate T2</u> | | | | |
| 32 | Direct Purchase Impact | 0.0420 | 59,256,000 | 24,917 |
| <u>Average Rate T2</u> | | | | |
| 33 | Direct Purchase Impact | 0.0420 | 197,789,850 | 83,169 |
| <u>Large Rate T2</u> | | | | |
| 34 | Direct Purchase Impact | 0.0420 | 370,089,000 | 155,620 |
| <u>Large Rate T3</u> | | | | |
| 35 | Direct Purchase Impact | 0.0958 | 272,712,000 | 261,162 |

Notes:

(1) Transportation bill impacts based on monthly demand (m³/d).

2021 SCORECARD RESULTS – ENBRIDGE GAS

1. The purpose of the scorecard is to measure and monitor performance over the deferred rebasing period. The scorecard is produced annually, with 2021 being the third presentation of the scorecard for the amalgamated utility. Within EB-2021-1049, the OEB found that scorecard provides valuable information during the deferral rebasing period and accepted Enbridge Gas's plans to improve the results of the two metrics that did not meet the performance standard in 2020. The OEB found that the 2024 rebasing proceeding is the appropriate time to review historical performance trends and consider customer implications prior to making any adjustments to the performance scorecard.
2. In 2019 and 2020 there was a positive performance trend for all but two metrics: Time to Reschedule a Missed Appointment (TRMA) and the Meter Reading Performance Metric (MRPM). In 2021 Enbridge Gas continued to demonstrate the positive performance trend for 16 out of 20 metrics. There continued to be challenges meeting the performance standard for TRMA and MRPM and in addition, Enbridge Gas did not meet the performance standard for Call Answering Service Levels (CASL) and Abandon Rate. The challenges meeting the target for two additional metrics is viewed as an anomaly as historically targets are exceeded for the metrics. Enbridge Gas continues to work to improve the results of all scorecard metrics through ongoing reporting of results, identifying the root cause for variances, and implementing initiatives targeting areas where improvement can be made.
3. Three of the four metrics that are below performance standard for 2021 were impacted by COVID-19 pandemic restrictions and the amalgamation of utility systems and processes. Enbridge Gas has developed plans and strategies to improve results and performance in each area.

4. The TRMA metric tracks the percentage of customers contacted to reschedule the work within two hours of the end of the original appointment time. The annual standard for TRMA is 100% and Enbridge Gas achieved 97.0% in 2021. This is consistent with prior year results which were 97.0% in 2019 and 97.3% in 2020. Efforts toward meeting the TRMA target of 100% are ongoing. A cross functional team meets regularly to review performance on this metric, to address issues, and to re-inforce training when necessary. Regional management teams meet monthly to drive performance as well. While Enbridge Gas acknowledges that promptly rescheduling missed appointments is an important part of achieving the SQR and customer service, attainment of a perfect 100% is not always possible. TRMA is the only Scorecard metric with a target of 100%; and does not allow for human error.
5. The MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5% and Enbridge Gas achieved a level of 5.0% in 2021. The result for 2019 was 0.7% and 4.4% in 2020. Enbridge Gas has faced challenges meeting the target since 2019 for several reasons, including the decision of a key meter reading vendor to no longer provide meter reading service resulting in the need to onboard a new vendor. Since March 2020, the Covid pandemic has presented additional challenges including closed businesses, increased customer sensitivity to contact with meter readers, and access issues during periods of lockdown. In addition, extreme weather events such as freezing rain, flooding, and heavy snowfall limited the ability to travel to properties and read meters. The new vendor was also still transitioning and learning the business in addition to experiencing ongoing staffing challenges including resourcing issues and illness/absence due to Public Health isolation/quartine requirements. These challenges continued into 2021. Despite the ongoing efforts of Enbridge Gas to improve the performance standard, the MRPM target of 0.5% will be challenging due to sheer size and geographic

reach, especially when complicated by variables such as extreme weather. Enbridge Gas continues to work to meet the performance metric through a mitigation plan that includes various methods to attain reads including: meter reading partners increasing hiring, working additional hours and knocking on doors to obtain reads; customer outreach through social media, monthly emails and texts to customers asking them to submit a reading; requesting a reading from customers when they contact the call centre; and engaging the Enbridge Gas Quality Assurance team to review consecutive estimates.

6. The CASL metric measures the number of calls reaching the general inquiry number answered within 30 seconds divided by the number of calls received. The yearly performance standard for Call Answering Service Level is 75% with a minimum monthly standard of 40%. The 2021 result was 64.3%. The 2021 result is viewed as an anomaly and not consistent with historical performance of 79.0% in 2019 and 75.2% in 2020. In July 2021, EGI harmonized the two legacy utilities Customer Information Systems (CIS), which involved moving 1.6M customers and their associated data from one CIS system to the other. In addition, the telephony system (IVR) was changed. Several changes, both pre and post integration, resulted in an increase in call volumes. Calls ranged from questions about passwords and account numbers to complex and extended calls. Covid has also impacted the contact centres due to increased illness and absence. To improve performance on the CASL metric, Enbridge Gas has identified and implemented several initiatives including recruiting temporary employees to assist with high call volumes, a post integration review of telephony (IVR) to ensure customer experience and decrease wait times, and a review of contact centre and billing processes. Enbridge Gas is committed to providing excellent customer service to all customers and in doing so meeting the performance standard of answering 75% of calls within 30 seconds.

7. The measure Abandon Rate is the percentage of callers who hang up while waiting for a live operator. The annual standard is not to exceed 10%. The 2021 result was 16.0%. As with the CASL metric, the 2021 result is viewed as an anomaly with historical performance of 2.5% in 2019 and 5.4% in 2020, exceeding the performance standard. The Abandon Rate metric was also impacted by the integration of systems in 2021 and the Covid pandemic. The increase in call volumes and staffing issues due to illness resulted in an increase in wait times driving the increased abandon rate. The mitigation plans in place for CASL will assist with reducing the abandoned call metric to less than 10%.
8. The OEB has found that Enbridge Gas's 2024 rebasing proceeding is the appropriate time to review historical performance trends and consider the customer implications before making any adjustments to the performance scorecard.¹ Enbridge Gas will be proposing changes to the scorecard in that proceeding to the TRMA metric and the MRPM.

¹ EB-2021-0149, OEB Decision and Order, Enbridge Gas – 2020 DVA & Earning Sharing Proceeding (January 27, 2022), page 12.

EGI SCORECARD 2021

| Performance Measure | Target | Actual | Actual | Actual |
|--|--------|--|--|--|
| | | 2021 | 2020 | 2019 |
| # CUSTOMER FOCUS (Service Quality & Customer Satisfaction) | | | | |
| 1 Reconnection Response Time (# of days to reconnect a customer) (# of reconnections completed within 2 business days/# of reconnections completed) | 85.0% | 96.9% | 98.9% | 98.1% |
| 2 Scheduled appointments met on time (appointments met within designated time period) (# of appointments met within 4hrs of the scheduled date/# of appointments scheduled in the month) | 85.0% | 94.5% | 98.8% | 98.5% |
| 3 Telephone calls answered on time (call answering service level) (# of calls answered within 30 seconds / # of calls received) | 75.0% | 64.3% | 75.2% | 79.0% |
| 4 Customer Complaint Written Response (# of days to provide a written response) # of complaints requiring response within 10 days / # of complaints requiring a written response | 80.0% | 100.0% | 100.0% | 100.0% |
| 5 Billing accuracy 'The requirement states that utilities should complete manual checks of their bills to verify data when a meter read demonstrates excessively high or low usage.' | | 384,858 manual checks completed as per QAP | 427,524 manual checks completed as per QAP | 429,386 manual checks completed as per QAP |
| 6 Abandon Rate (# of calls abandon rate) (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent) | 10.0% | 16.0% | 5.4% | 2.5% |
| 7 Time to Reschedule Missed Appointments (% of rescheduled work within 2 hours of the end of the original appointment time) | 100.0% | 97.0% | 97.3% | 97.0% |
| OPERATIONAL EFFECTIVENESS (Safety, System Reliability, Asset Management & Cost Control) | | | | |
| 8 Meter Reading Performance # of meters with no read for 4 consecutive months / # of active meters to be read | 0.5% | 5.0% | 4.4% | 0.7% |
| 9 % of Emergency Calls Responded within One Hour (# of emergency calls responded within 60 minutes / # of emergency calls) | 90.0% | 95.2% | 96.7% | 96.7% |
| 10 Compression Reliability % reliable for transmission compression | | 99.7% | 99.7% | 99.9% |
| 11 Damages per 1000 locate requests | | 1.95 | 2.22 | 1.97 |
| 12 Total Cost per Customer (\$ / Customer) | | 643.9 | 658.2 | 653.6 |
| 13 Total Cost per km of Distribution Pipe (\$ / km of Distribution Pipe) | | 16639.6 | 16928.5 | 16735.4 |
| PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation) | | | | |
| 14 Total Cumulative Cubic Meters of Natural Gas Saved (Net) (Millions) | | | | 2075.9 |
| FINANCIAL PERFORMANCE (Financial Ratios) | | | | |
| 15 Current Ratio (Current Assets / Current Liabilities) | | 0.71 | 0.66 | 0.75 |
| 16 Debt Ratio (Total Debt / Total Assets) | | 0.41 | 0.40 | 0.40 |
| 17 Debt to Equity Ratio (Total Debt / Shareholders' Equity) | | 1.06 | 1.01 | 0.98 |
| 18 Interest Coverage (EBIT / Interest Charges) | | 2.55 | 2.34 | 2.53 |
| 19 Financial Statement Return on Assets (Net Income / Total Assets) | | 2.07% | 1.97% | 2.25% |
| 20 Financial Statement Return on Equity (Net Income / Shareholders' Equity) | | 5.32% | 4.96% | 5.56% |

INTEGRATED RESOURCE PLANNING

2021 Annual Report

Enbridge Gas Inc.
May 31, 2022

Table of Contents

| | |
|---|----|
| 1. Introduction:..... | 2 |
| 2. IRP Integration..... | 3 |
| 3. IRP Pilot Projects..... | 6 |
| 4. IRP Stakeholder and Indigenous Engagement Update..... | 7 |
| 5. IRP Plan Update | 8 |
| 6. Asset Management Plan (AMP) Update..... | 8 |
| 7. Integrated Resource Planning Alternatives Update | 9 |
| 8. Technical Working Group Summary..... | 9 |
| 9. Interruptible Rates Update..... | 10 |
| 10. DCF+ Review | 10 |
| Appendix A: OEB IRP Direction..... | 12 |
| Appendix B: Binary Screening Results | 14 |
| Appendix C: Integrated Resource Planning Alternatives | 15 |
| Appendix D: Technical Working Group Report | 18 |

1. Introduction:

This inaugural Enbridge Gas Inc. (“Enbridge Gas”) 2021 IRP Annual Report (the “Report”) encompasses the period from July 22, 2021, through December 31, 2021.¹ Where appropriate, Enbridge Gas has included information on relevant IRP-related activities subsequent to the end of the 2021. This Report has been filed per the Ontario Energy Board’s (“OEB”) Integrated Resource Planning (“IRP”) Decision and Order (dated July 22, 2021) establishing an IRP Framework for Enbridge Gas (the “Framework”), where the OEB directed:

“Enbridge Gas shall file an Annual IRP Report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, the proceeding in which it may seek disposition of balances in the IRP Costs deferral accounts.

The OEB does not intend to approve the annual IRP report, but it could impact the OEB’s findings on the disposition of amounts in the IRP Costs deferral accounts or inform future proceedings.

The annual IRP report and the report from the IRP Technical Working Group are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts. The annual IRP report should include the following information:

- A summary of IRP stakeholding activities from the past year
- A summary of IRP engagement or consultation activities with Indigenous peoples
- Updates on IRP pilot projects underway
- Updates on incorporating IRP into asset management planning
- Updates on status of potential IRP Plans
- Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
- Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
- The most recent results of Enbridge Gas’s IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs
- A summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas’s system, and learnings from pilot projects and other jurisdictions
- Efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option
- Any other IRP-related matters established by the OEB.”²

¹ Future IRP annual reports will include the full calendar year.

² EB-2020-0091, Decision and Order, Appendix A, p. 22

2. IRP Integration

The establishment of the Framework has allowed Enbridge Gas to commence formally integrating IRP into its existing planning practices. Accordingly, Enbridge Gas reviewed its distribution and transmission planning practices and implemented changes including, implementation of the OEB approved IRP assessment process, and stakeholder engagement activities. In addition, Enbridge Gas is expanding existing processes to enable the effective evaluation and implementation of IRP alternative³ (“IRPA”) pilot and non-pilot projects.

In support of these integration activities Enbridge Gas is guided by the Guiding Principles established by the OEB in the IRP Decision:

- “Reliability and safety – In considering IRPAs as part of system planning processes, Enbridge Gas’s system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas’s customers must remain of paramount importance.
- Cost-effectiveness – IRPAs must be cost-effective (competitive) compared to traditional Facility Alternatives⁴ and other IRPAs, including taking into account impacts on Enbridge Gas customers.
- Public policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, and in particular the OEB’s statutory objectives for the natural gas sector.
- Optimized scoping – Recognizing that reviewing IRPAs for every forecast infrastructure project would be extremely time intensive, binary screening should be undertaken, to confirm which forecast need(s) should undergo evaluation of IRPAs, and to ensure a focus at the outset on efficient and effective IRPA investment.
- Risk management – Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers.”⁵

More detailed discussion of the steps towards IRP integration taken by Enbridge Gas follow:

Stakeholder Engagement

Stakeholder engagement activities are ongoing. Following the completion and filing of the Company’s 2023-2032 Asset Management Plan (“AMP”) in the fall of 2022, Enbridge Gas will commence IRP-related regional and geo-targeted stakeholder engagement. Stakeholder feedback received through these engagement activities will be reviewed and responded to (where appropriate) and will inform the Company’s consideration and development of potential IRP projects as well as future AMPs. For

³ The types of eligible alternatives are described in EB-2020-0091, Decision and Order, Section 7

⁴ Per the IRP Framework (EB-2020-0091, Appendix A, p.4), Facility Alternative is “synonymous with a traditional or conventional facility project”

⁵ EB-2020-0091, Decision and Order, p.27-28

a summation of the stakeholder engagement activities undertaken in 2021 see Section 4: Stakeholder and Indigenous Engagement Update.

Forecasting and Planning

Enbridge Gas regularly updates its long-term peak demand forecast and AMP (both comprehensive and limited updates depending upon timing and purpose). The objective of peak demand forecasting, and planning is to amass data, input, and insights to identify potential future system needs and constraints as well as their magnitude and timing. Early identification of future system needs and constraints is critical as the Company is obligated to reliably serve the firm contracted peak period demands of its customers.

A comprehensive discussion of Enbridge Gas' forecast and planning processes and any changes that have been made as a result of the establishment and implementation of the Framework will be filed in the Company's 2024 Rate Rebasing application in fall of 2022.

Need Identification

Following the completion of the forecasting process, Enbridge Gas compares the future forecast to the capacities of its existing facilities. A new system need/constraint is identified when Enbridge Gas determines that its current facilities cannot balance the new peak demand forecast with existing system facilities safely and reliably. When a constraint is initially identified, Enbridge Gas will verify its model with existing actual physical data, including pressure and temperature compensated consumption or flow, to ensure that the constraint is properly forecasted.

Baseline Facility Setting

Following the identification of a system need, Enbridge Gas develops the baseline facility that is required to meet the system need, absent any non-facility or IRPAs. It is necessary to understand this baseline facility as early as possible, as it provides a helpful point of comparison for other alternatives including IRPAs.

Binary Screening

Following the identification of a system need, Enbridge Gas will review the need relative to the Binary Screening Criteria established by the OEB in the Framework. If the system need passes Binary Screening, Enbridge Gas will then review and assess IRPAs or combinations of IRPAs that could meet the capacity requirements of the system need.

Binary Screening includes:

- **“Emergent Safety Issues:** If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and

- needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.
- **Timing:** If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.
 - **Customer-Specific Builds:** If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.
 - **Community Expansion and Economic Development:** If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.
 - **Pipeline Replacement and Relocation Projects:** If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval [\$2 million], then an IRP evaluation is not required."⁶

IRPA Technical Feasibility Assessment

For all system needs that pass Binary Screening, Enbridge Gas will assess which IRPAs could technically be used to defer, avoid or reduce the need/constraint relative to facility infrastructure. In other words, Enbridge Gas will ensure that the IRPA can serve the identified need prior to evaluating the IRPA on an economic basis.

Economic Evaluation

Enbridge Gas will test and compare the technical feasibility of both the baseline facility and any IRPAs on an economic basis using the OEB-approved DCF+ cost test. In the Decision, the OEB determined that Enbridge Gas has "some discretion in selecting an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in phase 2 and 3 or are difficult to quantify."⁷ The IRPA, or combination of IRPAs, that can technically and economically meet the system need and satisfy the Framework's Guiding Principles, will be incorporated into the AMP for inclusion into its broader planning activities, stakeholder touchpoints and for implementation at the appropriate time.

⁶ EB-2020-0091, Decision and Order, p.47-49

⁷ IBID, p.56

Project Development

Following the identification of IRPAs and the inclusion in the AMP, Enbridge Gas will begin work to develop and subsequently file an IRP Plan application and supporting evidence with the OEB for approval (where appropriate). Enbridge Gas will ensure that all details related to IRPAs and the underlying system needs that they are intended to address will be fully refined in this step and will continue to monitor the need as part of its planning activities until such time that the project is implemented.

IRPA Project Implementation

Enbridge Gas' IRP Plan applications will:

- detail anticipated savings or peak period impacts (on an hourly basis for distribution system assets and on a daily basis for transmission and storage system assets) together with the costs and ownership/operationalization arrangements proposed for IRPA investments;
- seek approval to spend and subsequently recover costs associated with investing in an IRPA(s);
- include additional applicable details for IRPAs such as design, administration, implementation, monitoring and reporting.

As is the case with traditional applications to the OEB seeking an Order of the Board for Leave to Construct facilities LTC applications, Enbridge Gas intends to consult with impacted landowners (where applicable), municipal governments, First Nations, Indigenous groups, and other affected stakeholders prior to filing its IRP Plan application with the OEB.

Monitoring and Reporting

Following implementation of approved IRPAs, the Company will carefully monitor their effectiveness in meeting the identified system need to ensure system constraints are being sufficiently resolved. Enbridge Gas will provide an annual report of IRPA effectiveness to the OEB as part of either its annual Rates application or Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, or as otherwise directed by the OEB. If any IRPA is not meeting the identified system need for which it was implemented, Enbridge Gas will propose corrective action in its report which may include, but not be limited to, proposals to implement additional IRPAs or new facilities.

3. IRP Pilot Projects

The OEB Directed Enbridge Gas to “select and deploy”⁸ two IRP pilot projects by the end of 2022.

⁸ EB-2020-0091, Decision and Order, p.94

The concept of developing and implementing two IRP pilots received universal support during the IRP proceeding.⁹ Parties recognized that these IRP pilots would be an effective approach to better understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects required to meet the identified need.

The Technical Working Group was created to, among other matters, provide input and insight into the selection and development of the IRP pilots.

At the time of writing this Report the specific pilot projects and associated IRPAs have not been determined.

Enbridge Gas plans to file the two IRP pilot applications by December 31, 2022 for OEB review and implementation based on the following schedule:

| | |
|---------------------------|---|
| June – August 2022 | Review potential IRP Pilot projects |
| September | Select two pilot projects |
| September - December 2022 | Develop IRP pilot evidence and applications |
| January – April 2023 | OEB Procedural process |
| May 2023 | IRP pilot project implementation |

4. IRP Stakeholder and Indigenous Engagement Update

As part of the Decision in the IRP Framework proceeding “the OEB has determined that the components of Enbridge Gas’s proposed Stakeholder Engagement Process will provide valuable input into Enbridge Gas’s IRP activities and shall be incorporated in the IRP Framework. The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholdering efforts.”¹⁰

IRP Website

In December 2021, an Enbridge Gas IRP website went live.¹¹ This is the initial phase of the website and allows for individuals to identify which regions are of interest and to register for any stakeholder engagement that will occur within the region(s) of interest. Individuals are welcome to register for as many regional engagement activities as they feel appropriate. By registering their emails,

⁹ EB-2020-0091, Decision and Order, p.90

¹⁰ IBID, p. 66

¹¹ <https://www.enbridgegas.com/sustainability/regional-planning-engagement>

individuals give permission to receive emails from Enbridge Gas in the future thus meeting the requirements of Canada's Anti-Spam Legislation (CASL).

The next phase of the website design is underway. This next phase will be available when a pilot project or IRP Plan is developed, and it will include additional regional functionality. The next phase will also allow interested individuals to sign up for webinars, in-person engagements, and to receive information about any presentations and/or responses to stakeholder feedback that is posted. It is anticipated that the second phase of the website design will be available prior to the launch of the first pilot project or IRP Plan.

Enbridge Gas has also implemented an internal working group that includes representation from Enbridge Gas' Municipal, Stakeholder and Community Engagement Group, Community and Indigenous Engagement and the IRP group to ensure that the internal resourcing and IT infrastructure developed to conduct, gather, and respond to the ongoing stakeholder engagement efforts in support of IRP will be sufficient to inform future planning efforts. This internal working group brings extensive stakeholder engagement experience and insight to the future IRP Stakeholder engagement plans. Enbridge Gas' various stakeholder engagement groups support efficient project execution with engagement activities in the field with project-area residents, local governments, and local organizations, in support of project objectives and business goals. They also regularly engage with key partners, including local municipal officials, business leaders, key landowners, emergency responders, and non-government organizations. Enbridge Gas anticipates engagement with Indigenous groups to commence in 2022 as IRP Plans are developed.

5. IRP Plan Update

Enbridge Gas has not developed or filed any IRP Plans with the OEB that can be reported at this time. Please see Appendix B for a list of projects that Enbridge Gas has completed the binary screening process following the OEB's IRP Decision.

6. Asset Management Plan (AMP) Update

The IRP Decision indicated that "for this first-generation IRP Framework, the OEB finds the process proposed by Enbridge Gas to identify system constraints or needs is acceptable. Recording potential system needs/constraints up to ten years in the future in the AMP will allow time for a detailed examination of IRPAs. The OEB agrees with Enbridge Gas's proposal that the first version of the AMP reflecting this updated process be filed in Fall 2022."¹²

¹² EB-2020-0091, Decision and Order, p.42

Enbridge Gas will file the 2023-2032 AMP in Fall 2022 with the 2024 Rate Rebasing application. The AMP will include the binary screening results for all facility projects, greater than \$2 million, as noted in the IRP Assessment process description above. In addition, the AMP will include IRP assessment information for the projects, including IRPAs, where possible.

7. Integrated Resource Planning Alternatives Update

Discussion during the IRP regulatory proceeding included the request by some parties to have available a listing or menu of IRPAs being considered by Enbridge Gas. The OEB concluded that a “document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report.”¹³

Appendix C lists the preliminary IRPAs and includes information on these specific IRPAs as suggested by OEB Staff including “types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas’s system, and learnings from pilot projects and other jurisdictions.”¹⁴ Enbridge Gas recognizes that this IRPA information is preliminary and will become more refined over time as the Company becomes more familiar with the actual impacts of these IRPAs on system peak demands and with the inclusion of more granular meter reading through an Automated Metering Infrastructure (AMI) application. Enbridge Gas also anticipates that the IRP pilot projects will provide further information allowing for the refinement and updating of the impacts of some of the IRPAs listed.

8. Technical Working Group Summary

The OEB’s July 22, 2021, Decision further instructed the OEB to establish an IRP Technical Working Group (TWG) led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

The inaugural meeting for the IRP TWG was held on Tuesday January 18, 2022. Any updates or summaries of IRP TWG meetings held in 2022 will be included in and reported on in the 2022 IRP Annual Report. All documents and presentations with respect to the IRP Technical working group can be found on the OEB web site under proceeding EB-2021-0246.¹⁵

The Report of the Technical Working Group is included as Appendix D.

¹³ EB-2020-0091, Decision and Order, p.36

¹⁴ IBID, p.34

¹⁵ <https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/natural-gas-integrated-resource>

9. Interruptible Rates Update

The use of interruptible rates as an IRPA was reviewed as part of the IRP Framework proceeding. The discussion centered around a few key issues: “Customers on interruptible rates pay a lower rate in exchange for the ability of Enbridge Gas to curtail delivery if capacity is not available on the system. Interruptible volumes are not included in Enbridge Gas’s design day assumptions. Therefore, increased use of interruptible rates could potentially reduce the amount of firm peak demand Enbridge Gas is obligated to serve, helping address a system need. For this reason, Enbridge Gas indicated that it does consider interruptible rates to be a type of IRPA. Enbridge Gas already offers interruptible rates to its Contract Rate customers (larger commercial, institutional and industrial customers). However, Enbridge Gas noted that customers have been moving away from interruptible rates as they value certainty of supply over cost reduction.”¹⁶

In response Enbridge Gas indicated that it would “investigate the drivers for recent declines in the use of interruptible services and could potentially file revised interruptible and firm seasonal services/rates to make them more attractive to customers as part of its 2024 rebasing application.”¹⁷

The OEB determined that “the impact of interruptible rates to meet a system need/constraint should be considered in an IRP Plan in combination with demand-side or supply-side alternatives.”¹⁸

Enbridge Gas will file an interruptible rates study as part of its Rate Rebasing application in fall of 2022.

10. DCF+ Review

As part of the IRP Framework Decision the OEB found that “the OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test (shown in Table 2) for the use of this test in the IRP Framework. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP.”¹⁹

The OEB further recognized that “this test could be improved to better list and define the costs and benefits of facility projects and IRP Alternatives and clarify how these costs and benefits should be considered within the test. Enbridge Gas is expected to study improvements to the Discounted Cash Flow-plus test for IRP, in consultation with the IRP Technical Working Group that will be established

¹⁶ EB-2020-0091, Decision and Order, p,30

¹⁷ IBID, p. 30-31

¹⁸ IBID, p.35

¹⁹ IBID, p.56-57

as part of the IRP Framework and using IRP pilot projects as a testing ground. Enbridge Gas shall file an enhanced Discounted Cash Flow-plus test for approval as part of the first non-pilot IRP Plan.”²⁰

Enbridge Gas has begun the process of reviewing the DCF+ test approved by the OEB. Enbridge Gas will consult with the Technical Working Group on any proposed enhancements to the DCF+ test prior to filing this cost benefit analysis with the first IRP non-pilot application.

²⁰ EB-2020-0091, Decision and Order, p. 5-6

Appendix A: OEB IRP Direction

The table below provides Enbridge Gas' progress with respect to meeting the Directions as ordered by the OEB in the IRP Decision.

| Direction Item | Reference in the Decision | Direction | Status |
|------------------------------------|---------------------------|---|---|
| Interruptible rates | Section 7 p.35 | The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service. | In progress – will be included with Enbridge Gas Rebasing Application (2023-2032) |
| Documentation of demand side IRPAs | Section 7 p.36 | The OEB concludes that a document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing. | Completed – preliminary list |
| Asset Management Plan | Section 8 p.42 | The OEB directs that the AMP include information about Enbridge Gas' system needs. This includes providing the status of consideration of IRP Plans in regard to meeting system needs, the result of the binary screening, and details on the evaluation. | In progress – will be filed with the Enbridge Gas Rebasing Application |
| DCF+ test enhancement | Section 8 p.56-57 | The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and, as applicable, file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan. | In progress |
| IRP Website | Section 10 p.66 | The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholder engagement efforts. | Phase 1 – Completed Phase 2 – In progress |

2021 IRP Annual Report

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|-------------------------|-----------------|---|-----------|
| Technical Working Group | Section 10 p.67 | Establishment of a TWG with the OEB directing that membership should include Enbridge Gas, OEB staff, independent experts, and experienced non-utility stakeholders | Completed |
| IRP Deferral accounts | Section 15 p.87 | The OEB directs Enbridge Gas to prepare a Draft Accounting Order for the two IRP Costs deferral accounts, consistent with the direction in this decision. | Completed |

Appendix B: Binary Screening Results

| Appendix B: Binary Screening Results for Projects Filed | | | | | | | |
|---|---|-------------------------|--------|----------------------------|-----------------------|--|---------------------|
| OEB Proceeding Docket | Project Name | Customer Specific Build | Timing | Pipeline Replacement >\$2M | Emergent Safety Issue | Community Expansion & Economic Development | Binary Pass or Fail |
| EB-2022-0111 | Bobcaygeon Community Expansion Project | | | | | Fail | Fail |
| EB-2022-0086 | Dawn to Corunna Replacement Project | | Fail | | | | Fail |
| EB-2022-0088 | Haldimand Shores Community Expansion Project | | | | | Fail | Fail |
| EB-2022-0003 | NPS 20 Waterfront Relocation Project | | Fail | | | | Fail |
| EB-2020-0293 | St. Laurent Ottawa North Replacement Project | | Fail | | | | Fail |
| EB-2021-0205 | Greenstone Pipeline Project | Fail | | | | | Fail |
| EB-2021-0248 | Coveny and Kimball-Colinville Well Drilling Project | | Fail | | | | Fail |

Appendix C: Integrated Resource Planning Alternatives

Integrated Resource Planning Demand-Side Alternatives – Best Available Information

As per the IRP Decision, the IRP Annual Report is to include “a summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas’s system, and learnings from pilot projects and other jurisdictions”.²¹

Demand-side IRPAs

| IRPA Name | Enhanced Targeted Energy Efficiency (ETEE) |
|--|--|
| ETEE IRPA Overview | |
| <p>Enhanced targeted energy efficiency (ETEE) programs focus on achieving necessary reductions in a specific geographical area to reduce peak period system demands. The mix of offerings and measures utilized in an ETEE program is dependent upon the scope of the facility investment project under consideration, customer characteristics in the specific project service area, past demand side management DSM participation etc. ETEE programs could include refining existing broad-based DSM offerings through enhanced incentives and targeted marketing or introducing new geo-targeted programs not offered through broad-based DSM.</p> <p>Broad-based DSM programs have been delivered throughout the Enbridge Gas service areas since 1993. The 2023-2027 DSM Plan (EB-2021-0002) is currently under consideration of the OEB to guide broad-based DSM programming over that time frame. As defined by the Ontario Energy Board in their DSM Letter, the objective of broad-based DSM is “assisting customers in making their homes and businesses more efficient in order to help better manage their energy bills”.²²</p> <p>Separately, Enbridge Gas proposes to undertake IRP pilots to review and understand the potential impacts of energy efficiency programs on peak period system demands within a geo-targeted area, and whether the impacts are significant enough to be considered an infrastructure alternative.</p> <p>Potential ETEE measures include those space heating equipment, water heating equipment and building envelope upgrades that could impact peak.</p> | |

²¹ The IRP Alternatives do not include electricity-based alternatives per the OEB’s EB-2020-0091 Decision where it stated “The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives.” p.4

²² EB-2019-0003, OEB Letter Post-2020 Natural Gas Demand Side Management Framework (December 1, 2020), p. 2.

| IRPA Peak Impacts |
|--|
| <p>Forecast peak impacts will be estimated on a case-by-case basis depending on the ETEE program.</p> <p>Enbridge Gas Inc. (EGI) worked with Posterity Group to build an end-use model of its service territory with the 2019 Achievable Potential Study (APS) being the starting point for the model creation. First, a mirror model of the APS was created and then several adjustments were made to better reflect EGI's knowledge and experience of the Ontario DSM market, EGI's current TRM assumptions and known changes to applicable standards. Then Posterity Group worked with EGI to develop peak factors which were added to the model so that enhanced targeted energy efficiency peak hour impacts estimates could be developed for each region, sector, segment and end use. Posterity Group and EGI plan to continue to evolve this model by refining assumptions and assessment methodologies to refine and improve forecasting of peak hourly flow reduction potential.</p> |
| IRPA Cost Details |
| <p>Costs will be determined on a case-by-case basis depending on the ETEE program.</p> <p>The Posterity model described above also included cost assumptions for ETEE programs. Posterity Group and EGI plan to continue to evolve this model by refining assumptions and assessment methodologies so it can be used to assess project specific costs for an ETEE program.</p> |
| EGI Deployment Strategy |
| <p>Which energy efficiency measures are chosen and what ETEE deployment strategy is undertaken will be dependent upon the scope of the facility investment project under consideration, customer characteristics in the specific project service area, past DSM participation etc.</p> <p>An IRP ETEE pilot project would provide insights that could guide the deployment strategy of a future IRP ETEE program, including to what degree Automated Metering Infrastructure (AMI) may be required to inform the objectives of the pilot.</p> |
| Learnings from Pilot Projects/Other Jurisdictions |
| <p>Enbridge Gas has engaged Guidehouse to undertake a jurisdictional review of ETEE (Enhanced Targeted Energy Efficiency) and DR (demand response) gas pilots implemented for the objective to defer or avoid infrastructure. Findings from the review are anticipated to inform potential pilots for natural gas IRP implementation.</p> <p>Enbridge Gas filed a Geo-Target Demand Side Management Case Study in EB-2020-0091 at Exhibit C, Appendix A. The objectives of the case study were:</p> |

| | |
|---|----------------------|
| <p>1.Assessment of the impacts of geo-targeted DSM programs on reducing peak hour demand. 2.Assessment of the costs of geo-targeted DSM program implementation.</p> <p>The results from this case study only illustrate the impacts geo-targeted DSM had on the town of Ingleside and although informative and directional, the results cannot be generally applied due to the specific nature of customer composition.</p> | |
| IRPA Name | Demand Response (DR) |
| IRPA Overview | |
| <p>Natural Gas Demand Response aims to reduce demand by natural gas customers during peak periods. For residential and commercial customers, this is usually in the form of heating demand reduction via thermostat control or water heater temperature settings. For contract customers, this can be done through leveraging Interruptible Rates.</p> | |
| IRPA Peak Impacts | |
| <p>Peak impacts will be determined on a case-by-case basis depending on the DR program.</p> | |
| IRPA Cost Details | |
| <p>DR IRPA costs will be determined on a case-by-case basis depending on the DR program.</p> | |
| EGI Deployment Strategy | |
| <p>The deployment strategy will be determined on a case-by-case basis depending on the DR program. An IRP Demand Response pilot project would provide insights that could guide the deployment strategy of a future Demand Response program, including to what degree Automated Metering Infrastructure (AMI) may be required to inform the objectives of the pilot.</p> | |
| Learnings from Pilot Projects/Other Jurisdictions | |
| <p>Enbridge Gas has engaged Guidehouse to undertake a jurisdictional review of ETEE (Enhanced Targeted Energy Efficiency) and DR (demand response) gas pilots implemented for the objective to defer or avoid infrastructure. Findings from the review are anticipated to inform potential pilots for natural gas IRP implementation.</p> | |

Appendix D: Technical Working Group Report

Review of Enbridge Gas Inc. 2021 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning
Technical Working Group

June 9, 2022

Contents

- 1. Introduction 3
- 2. Establishment and Initiation of Working Group..... 3
- 3. Review of Enbridge Gas’s Annual IRP Report and Comments on Implementation of the IRP Framework..... 6
 - 3.1. Working Group Comments on Implementation of the IRP Framework..... 7
- 4. Description of Other Key Activities to Date.....19

1. Introduction

An Integrated Resource Planning (IRP) Framework for Enbridge Gas was established by the OEB through its [July 22, 2021 Decision and Order](#) (the IRP Decision). The IRP Decision directed the OEB to establish an IRP Technical Working Group (Working Group) and required a report from the Working Group to the OEB (Working Group report) to be filed in the same proceeding in which Enbridge Gas's annual IRP report is filed. The IRP Decision indicated that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group, and may also describe other activities undertaken by the Working Group in the previous year.

This report has been prepared by OEB staff with input from all Working Group members, and approved by all Working Group members, as an accurate summary of the Working Group's activities.¹ Where views expressed in the report do not reflect the views of all members, this is clearly indicated.

2. Establishment and Initiation of Working Group

The IRP Decision instructed the OEB to establish a Working Group led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

The IRP Decision further required the OEB to establish a terms of reference and select the membership for the Working Group. On October 19, 2021, the OEB issued a [letter](#) seeking nominations from individuals interested in participating on the Technical Working Group as non-utility members. The OEB selected seven non-utility members from the twenty nominations received, and announced the establishment and initial membership of the Working Group in a [letter](#) issued December 6, 2021. In addition to non-utility members, the Working Group includes

¹ The IRP Technical Working Group includes observers from the Independent Electricity System Operator and EPCOR Natural Gas LP. As noted in the Working Group's Terms of Reference, any materials authored by the IRP Working Group (including this report) should not be considered to represent the views of Working Group observers, or their organizations.

representatives from the OEB and Enbridge Gas, and observers from the Independent Electricity System Operator and EPCOR Natural Gas LP.

The current membership of the Working Group is shown below.

Table 1: IRP Working Group Membership

| Name | Role |
|--|--|
| Michael Parkes | OEB staff representative (Working Group chair) |
| Stephanie Cheng | OEB staff representative |
| Chris Ripley | Enbridge Gas representative |
| Whitney Wong (replacing Amrit Kuner) | Enbridge Gas representative |
| Amber Crawford, Association of Municipalities of Ontario | Non-utility member |
| John Dikeos, ICF Consulting Canada Inc. | Non-utility member |
| Tamara Kuiken, DNV Inc. | Non-utility member |
| Cameron Leitch, EnWave Energy Corporation | Non-utility member |
| Chris Neme, Energy Futures Group | Non-utility member |
| Dwayne Quinn, DR Quinn & Associates Ltd. | Non-utility member |
| Jay Shepherd, Shepherd Rubenstein Professional Corporation | Non-utility member |
| Kenneth Poon, EPCOR Natural Gas LP | Observer |
| Steven Norrie, Independent Electricity System Operator | Observer |

The inaugural meeting of the Working Group was held on January 18, 2022. Meetings have subsequently been held on a monthly basis, with five meetings completed as of the date of this report.

Meeting notes and meeting materials for IRP Working Group meetings are published on the OEB's website following meetings to allow stakeholders to follow the Working Group's

progress.² These materials can be found at: <https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/natural-gas-integrated-resource>.

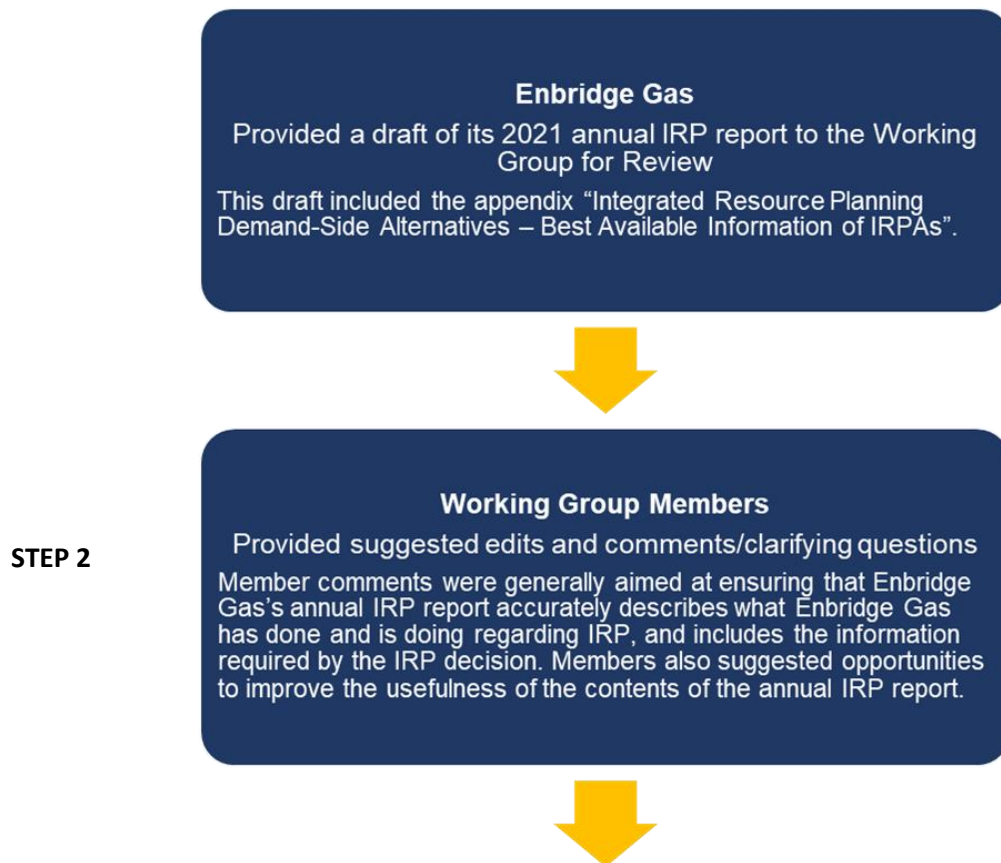
As required by the IRP Decision, a draft terms of reference for the Working Group was developed by OEB staff. Following review and input from Working Group members at the initial meeting, a [final terms of reference](#) was issued by the OEB on February 17, 2022.

² Meeting materials are typically posted online shortly after the meeting. Meeting notes are not typically posted until after the following meeting, to allow for members to review draft notes and identify any omissions or inaccuracies.

3. Review of Enbridge Gas's Annual IRP Report and Comments on Implementation of the IRP Framework

The IRP Decision notes that the Working Group is expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff, and that Enbridge Gas should provide a draft of the annual IRP report to the Working Group far enough in advance of its planned filing to the OEB to allow the Working Group time to review and comment. The IRP Decision also indicates that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group.

The Working Group's review took the following steps:



STEP 3

Enbridge Gas

Revised and finalized its annual IRP report

Enbridge Gas provided a revised draft to the Working Group, documenting how it had taken into account comments from Working Group members, and (after a second stage of review), finalized its annual IRP report. Final determinations as to the contents of Enbridge Gas's annual IRP report were made by Enbridge Gas, not the Working Group.



STEP 4

Working Group Members

Provided final comments on implementation of IRP Framework
Member comments are discussed further below in section 3.1

3.1. Working Group Comments on Implementation of the IRP Framework

All Working Group members (with the exception of observers) were asked the following question:

Question: Having reviewed Enbridge Gas's final annual IRP report's description of Enbridge's IRP activities in the previous year and having also participated on the IRP Working Group, do you have any comments or concerns with the implementation of the IRP Framework to date?

To varying degrees, all non-Enbridge Gas Working Group members expressed some concerns. These concerns relate primarily to: (1) the pace of Enbridge Gas's efforts to implement the IRP Framework since the IRP Decision in July 2021; and (2) the ability of the Working Group to make progress on its identified priorities (discussed in chapter 4 of this report) and meaningfully contribute to Enbridge Gas's IRP implementation, due in part to Enbridge Gas's determinations regarding the topics and level of detail that it has brought forward to the Working Group to date. More specifics are provided in the comments from individual members in Table 2, and the comments of Enbridge Gas Working Group members follow in Table 3.

Several members (including Enbridge Gas representatives) noted that more frequent meetings or focused subgroups may help advance progress on IRP implementation. The Working Group has agreed to add a second monthly meeting, with a subgroup focusing on the discounted cash flow-plus (DCF+) test, beginning in July 2022.

Table 2: Individual Comments of IRP Working Group Members

| Working Group Member | Comments (optional) |
|-------------------------------------|---|
| Amber Crawford (non-utility member) | <p>Since the Decision and Order was published on July 22, 2021, Enbridge Gas and OEB jointly created the nomination for membership of the IRP Technical Working Group. There have been five meetings held in 2022, and the following observations can be made thus far:</p> <p>Little Progress Made on IRP Pilot Projects: According to the Decision and Order, “the OEB expects that the [two] IRP pilot projects will be selected and deployed by the end of 2022.” (p.24). Meetings to date have discussed pilots at a very high-level, and have not yet seen substantive materials that would help the IRP Technical Working Group provide input on. While this may be in part due to Enbridge’s Asset Management Plan being developed this year, the criteria and potential choices should be further along to meet Enbridge’s deadline.</p> <p>Lack of Transparency and Reliance on 2024 Rate Rebasing: When asked to see data pertaining to pilots, the DCF+ test, binary screening results, best practices in other jurisdictions, or Enbridge’s Asset Management Plan, it has often been denied or mentioned it will be part of the 2024 Rate Rebasing in the Fall. Enbridges view that these topics are better addressed through testing of the evidence within the rebasing application. If this group is to provide input and expertise, it is incumbent on Enbridge to provide those details as otherwise, the consultation will not be meaningful.</p> <p>Minimal Information in Annual IRP Report: As a function of the slow progress in 2021, the Annual IRP Report fails to include details on key sections that would have been helpful and set up the 2022 year better (e.g. Sections 2, 6, 9). The Working Group’s review has been quite limited and question whether input to date has had a meaningful impact on Enbridge’s annual IRP report.</p> |

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|--|---|
| <p>John Dikeos (non-utility member)</p> | <p>I agree with many of the comments from other Working Group members that Enbridge's progress on identifying and screening potential IRPA pilots and updating its DCF+ cost-effectiveness approach has been relatively slow. There was very limited progress on these items in advance of the first Working Group meeting in January 2022 and progress since has been slow as well. To date, this has limited the Working Group's ability to provide more meaningful contributions to the future of IRPA planning in Ontario.</p> <p>I noted the following additional items based on my review of Enbridge's final 2021 IRP Annual Report:</p> <p>Evolution of binary screening criteria: Enbridge has included high-level details regarding its binary screening criteria for IRPAs. Although the criteria appear to be reasonable at this stage given the current knowledge and experience with IRPAs, Enbridge should be encouraged to revisit and evolve the criteria on an ongoing basis. For example, the Timing criteria should likely be condensed as Enbridge gains additional knowledge and experience with demand-side IRPAs.</p> <p>Interruptible rates: Enbridge notes that it is completing a study on interruptible rates, which will be filed as part of its rebasing application in fall 2022. As part of this study, Enbridge should investigate alternative and/or enhanced approaches to interruptible rates, such as the pilot projects that are being run by some utilities in New York (e.g., ConEd).</p> |
| <p>Tamara Kuiken (non-utility member)</p> | <p>I agree with many of the comments made by other reviewers, including those related to the lack of progress made on IRP pilots, the lack of progress made on improving the DCF+ test, communication about IRP elements delayed until the rebasing application, all initial IRPAs failing the binary test, and the perfunctory IRP Report.</p> <p>In my opinion, Enbridge shows little urgency toward advancing the IRP process, despite their commitment to deploy pilots before the end of 2022. The initial stated reason was a desire to engage with the TWG prior to making commitments; however, the lack of progress since the TWG was initiated suggests that other barriers exist.</p> |
| <p>Cameron Leitch (non-utility member)</p> | <p>From the definitions within the IRP Framework, this process is meant to address system needs by considering alternatives to conventional facility projects. At the core of this process is clarity on the determination of system needs, and without</p> |

| | |
|---------------------------------|--|
| | <p>insight into this determination (outside of the future AMP submission), it is difficult for the Working Group to provide meaningful feedback. Comments by other members of the Working Group are insightful, and my repetition of them will not provide added value to the reader.</p> |
| Chris Neme (non-utility member) | <p>While there have been some good initial discussions, and the tone of those discussions has been appropriately congenial and open-minded, I have several concerns about the effectiveness of the working group (WG) thus far. The most important are as follows:</p> <ol style="list-style-type: none"> 1. Input on key IRP issues related to the Company's next Asset Management Plan (AMP) and rate-basing application has essentially been taken off the table. Among those key issues are (A) the Company's approach to load forecasting in light of Canada's energy transition commitment, fast-increasing carbon taxes and the potential for the Company to partially control demand growth through limitations on new connections; (B) how binary screening criteria are to be assessed/applied, including the how the timing of needs is to be determined (given the binary screening criterion that says alternatives to traditional infrastructure investments should not be considered if the system need is within three years); and (C) how risks of stranded assets are to be addressed (e.g. if load grows in the near term but then declines as electrification takes hold). Had the Company been willing to engage on these issues prior to its filing in the Fall, some progress eliminating issues – or at least surfacing key issues and ensuring that the filing provided data/info likely to be important – could have been made, saving the Board time and making the filing a better product. These kind of collaborative working groups – speaking here to a groups addressing a range of topics, not just IRP – routinely provide such construction feedback in other jurisdictions. 2. Little progress on pilots – and therefore likely failure to begin deploy IRPAs as part of pilots before the end of 2022. This is particularly concerning given that it is essentially one of just two issues that the WG has effectively prioritized for 2022. While I appreciate that the Company may not have wanted to get too far in planning for the pilots until the |

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|--|--|
| | <p>WG had formed, it still could have done a lot of groundwork identifying potential projects/locations for pilots (e.g. maybe developing an initial short list of 10-12) so that we could have jumped right into selection once the WG had talked through priorities.</p> <p>3. No progress on the revisions to the DCF+ cost-effectiveness test. This also has relevance to the Company's upcoming AMP and rate-basing application, so it would have been ideal to have worked through some issues in greater detail in the first half of 2022.</p> <p>4. Enbridge's first IRP Report is largely perfunctory, with little useful information. This seems a function of two related things: (A) no IRPAs have been identified yet for deployment; and (B) the Company has decided that all planning related to IRPA consideration will be addressed in its AMP and rate-basing application. As stated above, the Company's decision to not bring its draft approach to applying the IRP framework to its AMP is an unfortunate missed opportunity. Hopefully next year's IRP report will be more substantive.</p> <p>Note that greater progress on the items above may have been hindered by having just one meeting a month among a dozen or more people. That might suggest the need for some subgroups focused on particular topics (e.g. cost-effectiveness test) and perhaps with fewer people involved to meet more often. Those subgroups could then report back draft recommendations for the full WG to consider. This model is being used very effectively, for example, by the Illinois Stakeholder Advisory Group (SAG) for energy efficiency. They have full working group meetings quarterly (used to be monthly) but have numerous subcommittees (also with regular meetings) and working groups (more episodically meeting to address specific topics that have more time-sensitive needs). See www.ilsag.info.</p> |
| <p>Dwayne Quinn (non-utility member)</p> | <p>As the last non-utility member to comment, instead of "piling on" regarding the lack of opportunity for the IRP WG to understand the lack of progress by the utility or even the behind the scene processes, we will simply support contributions of each of the other non-utility members. I am concerned that the Enbridge comments seem to dismiss consensus comments by the group. I believe the reality lies in the fact that Enbridge has not advanced even one single</p> |

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| | <p>concrete example of a potential pilot, which could have been used to allow input from the WG on process matters. The cumulative years of experience and aggregated intellectual capital of the committee is being wasted as we await something substantive to review and to initiate collaboration.</p> |
| Jay Shepherd (non-utility member) | <p><i>Very Little Has Been Done To Date.</i> This Report demonstrates that little was done from July 22 to December 31, 2021 to advance IRP in Ontario. The Report discloses that the following steps were taken in that 5+ month period:</p> <ol style="list-style-type: none"> 1. A bare bones website was created (perhaps a day's work), in which the primary functionality is the ability of customers to indicate their interest in regional constraints and the related IRPAs. However, there are no regional constraints or IRPAs identified, and will not be until the end of 2022 at the earliest. Enbridge promises future enhancements to the website late in 2022 or early in 2023. 2. A committee of the stakeholder engagement folks at Enbridge has been created, but they will have nothing to do until late 2022, when constraints and potential IRPAs have been identified. <p>Nothing else appears to have been done. No preliminary work was done on the pilots, or the DCF+ test, or best practices in other jurisdictions, etc. Or, if there was, none of it was brought to the attention of the IRP Working Group.</p> <p><i>Asset Management Plan – Refusal to Disclose.</i> In parallel, Enbridge has moved forward with its 2024-2028 Asset Management Plan, but does not appear to have incorporated IRP into that process. Further, when asked to provide information to the IRP Working Group on the process of the AMP, and how it was influenced by IRP, Enbridge refused to do so. Members of the working group sought a draft of the AMP, which should be substantially finalized at this point, but that disclosure was refused.</p> <p><i>Load and Demand Forecast – Refusal to Disclose.</i> Related to this, Enbridge has, in 2021 and 2022, been preparing its ten year load forecast for the AMP to be filed in the rebasing application, but has declined to share any information on that forecast with the IRP working group. It does not appear that Enbridge has taken any action so far to</p> |

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| | <p>influence that forecast downward through, for example, longer term planning for, or forecasting of, IRPAs.</p> <p>Posterity Group Model – Refusal to Disclose. Another refusal from Enbridge was the request from the IRP working group to see the Posterity Group model that Enbridge plans to use to assess IRPAs. Enbridge will not provide that model unless compelled to do so by the OEB.</p> <p>Interruptible Rates Study – No Consultation with IRPWG. At the same time, Enbridge has proceeded (in 2022, not 2021) with an interruptible rates study as it relates to IRP, but has not brought any information on that study to the IRP working group, and apparently does not intend to do so.</p> <p>100% Fail Rate in Binary Screening. To date, Enbridge has used binary screening on seven projects, and all have failed, in most cases because of Enbridge’s determination that the need must be met in under three years. One of these was the St. Laurent Phase 3 and 4 project, which the OEB determined in the EB-2020-0293 LTC application would not proceed at this time. It is not known yet whether the others that failed the screening can stand up to a similar independent review. No information on that binary screening has been provided to the IRP working group.</p> <p>Pilot Projects – Non-Compliance with OEB Direction. Enbridge also discloses in the attached Report that they will not comply with the OEB direction to “select and deploy” two IRP pilot projects by the end of 2022. They have unilaterally determined, without input from the IRP working group, that they will complete the “select” stage by the end of the year, but will not have the pilot projects “deployed” until the winter of 2023, rather than the winter of 2022.</p> <p>Against this contextual background, Enbridge has been adding to rate base at an average rate of \$100 million of capital additions per month since the IRP Decision, and is continuing to do so.</p> <p>The inescapable conclusion from this Report, and from the actions of Enbridge to date, is that their strategy is a “slow walk” of IRP, consistent with their past resistance to the concept.</p> |
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| <p>Mike Parkes/Stephanie Cheng (OEB staff representatives)</p> | <p>In OEB staff's view, Enbridge Gas is taking the initial steps (as documented in Enbridge's annual IRP report) to implement the IRP Framework in accordance with the OEB's direction. This includes participating in good faith on the IRP Working Group. Implementation of the IRP Framework is still at a preliminary stage. At this time, OEB staff provides additional comments on three topics:</p> <ul style="list-style-type: none"> <p>Slow start on IRP Pilots (section 3 of Enbridge Gas annual IRP report): The IRP Framework indicated that Enbridge Gas should develop and implement two IRP pilot projects, with the expectation that the pilot projects would be selected and deployed by the end of 2022.</p> <p>Based on the description in the annual IRP report and the information that has been shared with the Working Group, the amount of preparatory work done by Enbridge Gas in the months following the IRP decision in July 2020 to lay the groundwork for these pilots (in advance of seeking input from the IRP Working Group) was very limited.</p> <p>While OEB staff recognizes that this was in part because Enbridge Gas did not want to overly constrain pilot design prior to receiving input from the Working Group, the result is that it is unlikely that pilots will be deployed (if "deployed" is interpreted to include having received an OEB approval) by the end of 2022, which was the expectation of the IRP Decision. The consequence is that there will be a related delay in transferring learnings from the pilots into Enbridge Gas's system planning decisions. It will be important for Enbridge Gas to make use of learnings from the pilots while they are still in-flight, to inform Enbridge Gas's consideration of IRP alternatives in system planning.</p> <p>Insufficient information base to compare IRP Alternatives Versus Facility Projects (sections 2,7, appendix B of Enbridge Gas annual IRP report): Under the IRP Framework, Enbridge will use a four-step IRP Assessment Process to determine the best approach to meeting system needs. Where such system needs pass an initial binary screening, Enbridge Gas is required to assess the technical and economic feasibility of IRP Alternatives in comparison with traditional facility solutions.</p> |
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| | <p>The level of detail in appendix B (<i>Integrated Resource Planning Demand-Side Alternatives – Best Available Information</i>) of Enbridge’s initial annual IRP report regarding IRP Alternatives, including their cost and peak demand reduction potential, is generally insufficient to assist Enbridge Gas in completing this step of IRP assessment, and will need to be improved in future annual IRP reports.</p> <p>Information on IRP Alternatives will be informed and improved by the results of Enbridge Gas pilots. However, Enbridge Gas will need to conduct IRP assessments prior to completion of the pilots (e.g. for potential system needs identified in Enbridge’s rebasing application). In OEB staff’s view, Enbridge will need to supplement the information obtained from IRP pilots with other sources of information on the expected cost and peak demand reduction potential of IRP Alternatives (including results from other jurisdictions), to assist it in completing IRP Assessments (and to assist the OEB in reviewing Enbridge Gas’s determinations). Otherwise, the risk is that no IRP Alternatives will advance past this stage of IRP Assessment for many years.</p> <ul style="list-style-type: none"> Limited information and Working Group review of IRP elements of rebasing application (sections 2, 6, 9 of Enbridge Gas annual IRP report): The OEB’s review of Enbridge Gas’s rebasing application (expected to be filed in November 2021) will have significant consequences for implementing the IRP Framework. Issues of particular importance noted briefly in the annual IRP report include: Enbridge Gas’s updated asset management plan and its approach (and conclusions) regarding screening system needs for IRP alternatives and reporting on the status of such consideration (section 6), Enbridge Gas’s approach to demand forecasting (section 2), and Enbridge Gas’s approach to studying the potential for interruptible rates (section 9). In OEB staff’s view, Enbridge Gas’s approach to demand forecasting in light of the energy transition to lower-carbon energy sources will likely have significant implications for IRP and system planning, both regarding identification of system needs and the role of IRP Alternatives as potential solutions. |
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| | <p>These issues are only mentioned briefly in the annual IRP report, and the Working Group has not to date been provided with substantive details of how these topics will be addressed in Enbridge Gas's rebasing application, and has not commented on them. At this point in time, if any review by the Working Group occurs, it will likely be quite limited. Reasons for this include: these topics were not identified as a priority for the Working Group in the IRP Framework; Enbridge Gas's view that these topics are better addressed through testing of the evidence within the rebasing application; and views of some Working Group members that input at this stage is unlikely to have a meaningful impact on Enbridge Gas's application. The consequence is that these issues will be addressed in the rebasing application without significant prior input from the Working Group.</p> |
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Table 3: Comments of Enbridge Gas IRP Working Group Members

| Working Group Member | Comments (optional) |
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| Chris Ripley/Whitney Wong (Enbridge Gas representatives) | <p>Enbridge Gas has structured its comments to follow the Working Group Participant comments above. For context, Enbridge notes that the Working Group's focus, per the Terms of Reference and the OEB's IRP Decision, are three main issues: the IRP Annual Report, the DCF+ cost/benefit test and the IRP Pilots. Enbridge Gas does not agree with the negative tone of many of the Working Group Participant comments. Enbridge Gas has been working diligently on IRP implementation and engaging responsibly with the Working Group, in a manner consistent with the OEB's directions and expectations from the IRP Framework. As described below, Enbridge Gas expects that the pace of Working Group progress and activities will increase in the coming months.</p> <p>Minimal Information in Annual IRP Report: As noted above, the 2021 IRP Annual Report is reporting on 2021 activities and information. While progress has been made on the three main Working Group tasks; Annual Report, DCF+ and pilots the work has been largely completed in 2022 and will appear in the 2022 IRP Annual Report. In addition, in Enbridge's view there is a mismatch between the IRP Annual Report, which relates to 2021, before the Working Group held its first</p> |

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| | <p>meeting, and the comments from the Working Group members on that Report, almost all of which relate to the experience of the Working Group in 2022. Over the next few months, the Working Group will discuss potential pilot projects and review Enbridge Gas' proposals for the DCF+ Test.</p> <p>Little Progress Made on IRP Pilot Projects: Enbridge does not agree with the Working Group comments suggesting Enbridge Gas made little effort on the IRP Pilots Projects. The OEB's IRP Decision stated "the OEB expects that the [two] IRP pilot projects will be selected and deployed by the end of 2022." (p.24). Enbridge acknowledges deployment by the end of 2022 is not possible, this is entirely due to the timing of Enbridge's demand forecast and planning processes being completed in Q2 of 2022. The 2023-2032 Asset Management Plan ("AMP"), generated in May 2022, identifies the needs on Enbridge's system. The pilot projects need to be, and will be, based on actual system needs that have been identified in Enbridge Gas' AMP. Enbridge Gas has included an updated IRP pilot schedule in its Annual Report. Enbridge Gas will bring 4-5 actual system needs for each of the two proposed IRP Pilots to the Working Group, including all relevant information to the need. Enbridge Gas will discuss the system needs brought forward with the Working Group, select two IRP Pilot projects and then prepare an application for the OEB's review and approval. In order to complete the IRP Pilot selection process quickly, Enbridge Gas proposed to increase the number of Working Group meetings from once per month to twice per month.</p> <p>DCF+ Test: Enbridge Gas engaged Guidehouse Consulting to conduct a review of the DCF+ test approved by the OEB in the IRP Decision. Enbridge Gas expects to receive the Guidehouse Final Report in June 2022 and will use the Guidehouse report in its review of the DCF+ test and in any proposed changes. Enbridge Gas will be communicating the Guidehouse Report and Enbridge Gas' proposed changes in the July IRP Working Group meeting. As discussed at the Working Group, a sub-group will be established to review the Guidehouse Report and Enbridge's associated proposed changes to the DCF+ Test. This review and discussion will happen prior to the cost test being applied to the IRP Pilot projects or an IRPA Plan.</p> |
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| | <p>Lack of Transparency and Reliance on 2024 Rate Rebasing: Enbridge Gas is filing its 2024 Rebasing Application in Fall 2022 which will include a comprehensive review of Enbridge Gas’ planning processes, the demand forecast and the Asset Management Plan. Enbridge Gas never understood the Working Group would provide input on the demand forecast process and the asset management requirements. The appropriate time to review Enbridge Gas’ planning processes and the Asset Management Plan is in the Rebasing proceeding, not at the IRP Working Group. Enbridge Gas is holding a Rebasing Stakeholder meeting in June 2022 where Enbridge will provide information about the upcoming filing. Enbridge Gas notes there is no direction to review or provide the planning processes, demand forecast or the Asset Management Plan to the Working Group in the OEB’s IRP decision or the IRP Working Group Terms of Reference</p> <p>Posterity Model: The Working Group have requested Enbridge Gas to provide the model used by Posterity Group to assess energy efficiency opportunities on Enbridge Gas’ system. Enbridge Gas does not own the Posterity model and cannot provide it. Enbridge Gas will explain the model, how it is used and the inputs/outputs as it develops the IRP Pilots.</p> <p>Interruptible Rates: In its IRP Decision, the OEB ordered Enbridge Gas “to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service. This initiative is expected to help reduce peak demand, and the study should be filed as part of the next rate rebasing application”. (p.35). Enbridge is completing this direction and it will be filed in the Rebasing Application. Enbridge Gas notes there is no direction to review the Interruptible Rates study with the Working Group in the OEB’s IRP decision or the IRP Working Group Terms of Reference.</p> |
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4. Description of Other Key Activities to Date

The Working Group's Terms of Reference confirmed the following items noted in the IRP Decision as the highest initial priorities for the Working Group (in addition to the review of Enbridge Gas's annual IRP report):

- **Consideration of IRP pilot projects to better understand how IRP can be implemented to avoid, delay or reduce facility projects.**
 - The IRP Framework indicated that Enbridge Gas is expected to develop and implement two IRP pilot projects. The pilots are expected to be an effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects. The IRP Framework indicated that the OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022.
 - Working Group activities: The Working Group has had several discussions to provide input to Enbridge Gas on pilot design, focusing primarily on the pilot objectives, the criteria that will be used to select and prioritize pilots, and the types of IRP Alternatives should be a priority to test in the pilots. Enbridge Gas has proposed four potential pilots built on different types of IRP Alternatives: (1) enhanced targeted energy efficiency in combination with a bridging supply-side solution; (2) a peak shaving supply-side IRP Alternative using either compressed natural gas or liquefied natural gas; (3) a demand response program focused on general service customers' heating loads; and (4) a demand response/interruptible rates initiative focused on Enbridge Gas's larger contract customers. Enbridge Gas is also considering a geographical IRP pilot that may address multiple needs within a specific area and include a suite of IRP alternatives, potentially including demand-side and supply-side IRP alternatives, as well as considering enhanced inspection/integrity management measures. In the coming months, it is expected that Enbridge Gas will propose specific projects that match these potential pilots to real system needs identified in its Asset Management Plan, for Working Group review, prior to Enbridge Gas's final selection of pilots. Additional discussion and refinement of the pilot proposals will take place by the Working Group, prior to Enbridge Gas filing pilot applications to the

OEB for approval.

- **Enhancements or additional guidance in using the Discounted Cash Flow-plus economic evaluation methodology to assess and compare the costs and benefits of using either facility solutions or IRP alternatives to meet system needs.**
 - The IRP Framework established a three-phase discounted cash flow-plus (DCF+) test as the economic evaluation that will be used to compare the costs and benefits of different approaches to meeting system need (IRP alternatives, facility alternatives, or a combination). The OEB concluded that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRP Alternatives, and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. Enbridge Gas was directed to study improvements to the DCF+ test, and encouraged to consult with the Working Group, and use the IRP pilot projects as a testing ground. Enbridge Gas was directed to file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.
 - Working Group activities: The Working Group has had several preliminary discussions on this topic. This included an analysis and *presentation* by Working Group member and cost-effectiveness expert Chris Neme, which made several proposals to improve or refine the DCF+ test, while remaining consistent with the OEB's guidance on this topic in the IRP Decision. Enbridge Gas is also planning to propose several refinements to the DCF+ test, but these have not yet been discussed with the Working Group. In the coming months, the Working Group plans further discussion, with the goal of agreeing on a preliminary approach to cost-effectiveness that can be used for the IRP Pilot applications. Additional work will be done as needed to address issues that were not completely resolved at the time of filing the pilot applications, and may include development of a supporting guidance document regarding use of the DCF+ test.

The Working Group has also discussed whether to give any consideration to the IRP-related aspects of Enbridge Gas's rebasing application, which would likely be contingent on the degree

of information that Enbridge Gas will provide regarding its application. Enbridge Gas has recently indicated that it will bring forward information on one IRP issue that will be part of rebasing - Enbridge Gas's approach to interpreting the IRP Framework's criteria for screening system needs - for discussion at an upcoming Working Group meeting, and is considering whether other IRP-related aspects of the rebasing application, including the draft Asset Management Plan, can be discussed with the Working Group.

Other potential areas of work for the Working Group in the future may include addressing:

- Learnings from natural gas IRP in other jurisdictions
- Performance metrics for IRP
- Accounting treatment of IRP costs
- Treatment of stranded assets in system planning
- Other activities relevant to the IRP Framework, as identified by the Working Group or as directed by the OEB

The Working Group has not to date discussed these topics in any depth (with the exception of some consideration of IRP in other jurisdictions with regards to pilot proposals).

A draft Work Plan is maintained for the Working Group and updated on a regular basis, outlining workstreams and expected timing of key deliverables.