PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DÉFENSE DE L'INTÉRÊT PUBLIC

ENBRIDGE GAS INC.
2020 RATES - PHASE 2

EB-2019-0194

Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

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Vulnerable Energy Consumers Coalition

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Summary

Phase II of these proceedings considers four issues: (1) Enbridge Gas Inc.'s (EGI or Enbridge) Incremental Capital Module (ICM) proposal; (2) cost allocation methodological changes; (3) changes to the practice of EGI's eBilling; (4) the submission of an Unaccounted for Gas (UFG) Report.

On these issues VECC submits the following:

- The Don River Replacement ICM request should be denied
- The Windsor Line Replacement Project ICM request should be allowed with modifications to the allowable ICM amount and an adjustment to eliminate any used and useful assets retired as part of this project.
- The cost allocation study should be set aside and a future panel of the Board should consider cost allocation and rate design for the new combined Utility in the next cost of service proceeding.
- Paper billing should remain the default billing option and customers should be provided the opportunity to select eBilling or paper billing easily and transparently.
- The Board should direct the Enbridge to file a comprehensive study on the reasons for, the mitigation of, and the cost allocation of Unaccounted for Gas (UFG) in its next cost of service proceeding.

Our detailed submissions on these issues are below.

Proposed ICM

<u>Don River</u>

Enbridge's ICM proposal consists of two projects. The Don River Replacement Project is to replace an NPS 30 XHP pipe crossing the Don River. The Board found in EB-2018-0305 that the Don River Replacement Project does not qualify for ICM funding as there was at that time no eligible incremental capital available for the EGD rate zone. A year later with the project delayed by a few months the Utility argues that it does meet the 2020 material threshold of the ICM formula.

In writing to the Board to vary the conditions of its leave-to-construct order the Applicant explained:[1]

> *Enbridge was delayed in starting construction of the new NPS 30 pipeline due to permitting delays. In the original plan there were two options to tie-in the pipe: (1) to tie-in during the planned maintenance shut-down of a large volume customer, and (2) to use a bypass if the planned maintenance option was missed in Fall 2019. The permit delays have affected the*

[1] I.VECC.1 Attachment 3,page 2 of 2

entire project schedule including the timing of when the pipeline can be tied in. As a result, the earliest that the tie-ins could occur, if the bypass option is utilized, would be December 2019 with completion in Q1 2020.

The Board scrutinized the reasons for the delay finally approving the relief sought on December 5, 2019. The updated schedule changes reinstatement (in-service) from October 2019 to May 2020.[2]

That a modest shift of timelines should upend the prior decision is, in our view, inherently illogical. It cannot, we submit, be just and reasonable to exclude a project based on an implementation in 2019 and be reasonable and just to include it because of a short delay in the in-service of that project. When asked by VECC to explain this they responded:[3]

The Board did not decline to provide ICM treatment for the Don River Project on the basis of the need or prudence of the project, but on the basis of the change in the Maximum Eligible Capital Amount, as compared to the In-service capital at that time. As noted in Exhibit B, Tab 2, Schedule 1, pages 18 and 19, "the identification of risks and the execution of projects is dynamic." As a result, "the delay to the implementation of the Don River Replacement project and other change to the 2020 portfolio resulted in reprioritization of capital outlined in the Addendum in Table 2.1-1. As such, the in-service capital for 2020 was revised, allowing Enbridge Gas to accommodate a portion of the Don River replacement project within the ICM threshold, leaving $26.8 million of in-service capital requiring ICM funding

We are not disputing the need for the project. We are disputing whether there is an additional ratepayer burden during the incentive period time frame because of Enbridge's delay in <u>completing</u> the project. It is not as if the entire project was being deferred to time period. The project was substantively completed by the end of 2019.

If the Board were to accept the argument of the Applicant then it would follow that any project might be manipulated - delayed or advanced – so as to maximize the benefit to the shareholder.

VECC has argued before that a key element of ICM funding is that it must be proposed in advance of the start of an ICM project and approval sought at its conception[4]. The ICM policy is not "post facto" rather it is premised on the need to find relief for projects which are outside the normal capital planning of a utility either in intent (like an emergency issue) or in materiality.

The Board has reviewed this proposal before and denied funding. Taken afresh the project is now complete or substantively so, in our view, cannot be eligible for ICM funding.

[2] I.VECC.2
[3] I.VECC.3
[4] See Oakville Hydro EB-2019-0059

Furthermore the project is some $10 million over the forecast cost presented in EB-2018-0108.[5]

Item No.	Description	Cost As Filed in EB-2018-0108	Updated Cost Estimate	Variance
		a	b	b-a
1.0	Material Costs	$710,107	$710,107	$0
2.0	Labour Costs	$17,060,285	$17,060,285	$0
3.0	External & Regulatory Costs	$860,000	$1,433,528	$573,528
4.0	Land Costs	$301,000	$2,264,746	$1,963,746
5.0	Overhead Costs	$759,000	$9,989,358	$9,230,358
6.0	Interest During Construction	$208,255	$209,093	$838
7.0	Contingency Costs	$5,698,892	$3,687,764	($2,011,128)
8.0	Total Project Cost	$25,597,539	$35,354,881	$9,757,342

The cost estimate in the LTC Application (EB-2018-0108) includes only direct overhead costs, and not indirect overheads. The inclusion of indirect overheads in the ICM request is the main driver of the noted cost difference. Enbridge notes that OEB confirmed that indirect overhead costs (capitalized overheads) are appropriately included in the ICM funding calculation in the September 12, 2019 Decision and Order in EB-2019-0305. Nonetheless given the prior ICM decision it is our submission that none of the costs incremental that presented in EB-2018-0108 is eligible for ICM funding in any event.

Enbridge's proposal to rehear the same matter again strikes against the principle of *res judicata*. The Board has decided the matter. A modest change in in-service dates is not a sufficient reason to review the Board's prior decision. Otherwise there would be no certainty in these ICM (or for that matter ACM) proceedings. But for the delay in timing of completion the Utility would not be provided relief. And while we cast no aspersions to do otherwise is an invitation to regulatory gaming.

Windsor NPS 10

The second ICM project is replacement of the Windsor NPS 10. Approval (EB-2019-0172) was granted on April 1, 2020. The OEB approved a total estimated cost of the Project of $105.5M. This is $13.5 million higher than the original class 5 estimate of the project[6] and is comprised $76.1M for the main pipeline, $15.3M for ancillary facilities (stations and services), and $14.1M in indirect overhead costs. We also note the Board approved an amount slightly different than the $106.8 million explained as the project costs in response to I.VECC.6 (and I.SEC.11). In our view the amount that should be used for the calculation of the ICM is that approved in EB-2019-0172.

Construction of the Project is scheduled to begin in May 2020 and is expected to be in-service in November 2020.

[5] I.VECC.4
[6] See I.FRPO.24, Attachment 1, page 10

In our submission the project should be eligible for ICM funding. However, if approved the Board should adjust the ICM funding to take into account the undepreciated value of the current Windsor line that is being replaced. This amount remains in rate base until rebasing and the current rates are derived in recognition of that fact. It follows that the ICM funding should be reduced in recognition of the returns already provided in rates for undepreciated capital that is being replaced and which will not be recognized until the next rebasing application.

We also submit that the Board should modify the allowable ICM funding in recognition of the actual 2019 capital additions. Doing so would reduce the allowable ICM funding by approximately $10 million.

Cost Allocation and Rate Design

Enbridge Gas has requested approval of the cost allocation methodology study results in order, in their view, to comply with the Board's directive from the MAADs Decision. However, the Utility proposes to wait until rebasing to implement the proposed cost allocation changes related to the Panhandle and St. Clair System, Parkway Station and Dawn Station.[7] The proposed changes would have significant impacts on customers as shown in the table below[8].

Table 1
Rate Class Impacts of the Proposed Panhandle / St. Clair
Cost Allocation Methodology Change

Line No.	Rate Class	Current Approved Revenue (1) ($000's)	Proposed Panhandle / St. Clair (2) ($000's)	Rate Class Impact (%)
		(a)	(b)	(c) = (b / a)
1	Rate M1	455,310	5,121	1.1%
2	Rate M2	67,068	1,742	2.6%
3	Rate M4	28,675	3,829	13.4%
4	Rate M7	12,450	1,216	9.8%
5	Rate T2	67,147	(4,886)	-7.3%
6	Rate C1 - Other (3)	30,793	(6,948)	-22.6%

With respect to the cost allocation study there are two issues to consider – the merit of the study and its implementation. With respect to the former we suggest that the underlying premise of this study may be upended when comprehensive consideration is given to cost allocation of the

[7] I.LPMA.2
[8] I.EP.16

amalgamated Utility. Fundamentally the study now provided is “Union” focused reflecting on the rapidly aging historical premise of gas supply and transmission delivery of this former utility.

With respect to the implementation of the study we agree in part with Applicant’s proposal. Enbridge has proposed to defer implementing the results of the study and in the alternative implementing any Board approved changes in the 2021 rate year[9]. Specifically we agree with the position of EGI that it is optimum to cost allocation changes in conjunction with the more comprehensive exercise rate design in a cost of service proceeding.   If so it follows that in such a proceeding the entire exercise should be revaluated. We see no need or value in attempting to fetter a future panel who will have a broader scope, a more thorough process, and likely more extensive evidence, in their examination of the appropriate cost allocation and rate design of the new amalgamated utility.

The Board sought this study to try and understand the impacts of recent capital projects undertaken by the former Union Gas. What the exercise has shown is that the matter is complicated both in determining the principles to apply in the actual study and how it should be implemented.

With respect to implementation Enbridge Gas anticipates there will be additional changes at rebasing in 2024 when it introduces rate harmonization, the integration of the cost allocation studies of the combined utility and the pass-through of synergy cost savings into rates. Furthermore there are further practical complications with the timelines by which any change might be included in rates in any event[10].

> *Enbridge Gas estimates it will require approximately three months following the Board’s direction in this proceeding to file a draft rate order incorporating the cost allocation study results including a proposal for adjustments to the unit rates for rate design factors. The Company expects the draft rate order submission will also include a proposal for any adjustments to the base amount used to calculate deferral and variance accounts for consideration at the same time. Enbridge Gas estimates approximately one month will be required to provide for comments from Board staff and intervenors on the draft rate order and proposal for deferral and variance accounts followed by a response from the Company. A final decision from the Board on the draft rate order will follow. If adjustments are required from the unit rate changes proposed by Enbridge Gas following the Board’s decision, the Company estimates it will require up to three weeks to incorporate the adjustments in the final rate order for approval. In order to implement the final rate order with a QRAM proceeding, the Company requires approval of the final rate order from this proceeding one month in advance of the QRAM implementation date. Enbridge Gas estimates the process of a final rate order could take up to six months once the Board provides direction in this proceeding until the Company could implement in rates with a QRAM*.

[9] See I.Staff.4
[10] I.IGUA.6

With respect to the proposed principles of the studies there are a number of issues that need to be considered carefully. The increase in residential and small commercial rates that results is not so much caused by the exercise intended to be examined by the Board but by the realignment of rate base.

> *The 2019 cost allocation study includes distribution-related rate base and operating costs additions since 2013 which has resulted in a shift of indirect costs away from transmission-related functions and into the distribution-related functions within the cost study. This shift of costs into distribution-related functions results in a reduction to transmission-related costs relative to current approved rates*[11].

However, this study takes into consideration only the Union portion of rate base and it is unclear to us the implication of the combining of the two former utilities into a single rate base. And as pointed out in the response to I.BOMA.4 changes to accounting practice that may also affect future cost allocation.

The matter is also complicated. Consider the number of decisions to be made only with respect to the Dawn assets:[12]

Table 1
Board-approved and Proposed Cost Allocation
Methodology Dawn-Parkway and Dawn Station Assets

Description	Board-approved Cost Allocation Methodology	Proposed Cost Allocation Methodology
Dawn-Parkway Transmission		
Dawn-Parkway Easterly Demand Costs excluding Parkway Station	Distance-weighted design day demands	Distance-weighted design day demands
Parkway Station Compressor Costs	Distance-weighted design day demands	Easterly design day demands requiring Parkway compression
Parkway Station Measuring and Regulating Costs	Distance-weighted design day demands	Bi-directional design day demands of the Parkway Station
Other Parkway Station Costs	Distance-weighted design day demands	Parkway Station measuring and measuring and regulating and compressor net plant
Dawn Station		
Dawn Station Compressor Costs	Design day demands requiring Dawn compression	Distance-weighted design day demands
Dawn Station Measuring and Regulating Costs	Distance-weighted design day demands	Design day demands requiring Dawn compression

[11] I.BOMA.3
[12] I.FRPO.23

In the result the new cost allocation studies also suggests significant changes in design day demands[13]

UNION RATE ZONES

Comparison of St. Clair and Panhandle System Design Day Demand Percentages

Line No.	Rate Class	Cost Study Proposal Design Day Demands - St. Clair System (1)	Cost Study Proposal Design Day Demands - Panhandle System	OEB Approved Cost Allocation Design Day Demands	Difference
		(a)	(b)	(c)	(d) = (b-c)
	Union South				
1	Rate M1	-	32.6%	14.0%	18.7%
2	Rate M2	-	11.1%	4.8%	6.4%
3	Rate M4	-	21.3%	7.8%	13.5%
4	Rate M5	-	0.1%	0.0%	0.1%
5	Rate M7	-	6.9%	2.6%	4.3%
6	Rate T1	-	4.5%	2.1%	2.4%
7	Rate T2	-	23.5%	32.7%	-9.2%
8	Total Union South	-	100.0%	63.9%	36.1%
	Ex-Franchise				
9	Rate C1	100.0%	-	33.3%	-33.3%
10	Rate M16	-	-	2.7%	-2.7%
11	Total Ex-Franchise	100.0%	-	36.1%	-36.1%
12	Total	100.0%	100.0%	100.0%	-

Notes:

(1) The proposed allocation of St. Clair System demand costs direct assigns all costs to Rate C1.

All of these issues make it difficult, we respectfully suggest, for the current Panel to be in a good positon to make a precedential decision on a narrow consideration of cost allocation issues.

Enbridge has stated that it plans to undertake a review of the cost allocation methodology of its entire system for its next rebasing application[14]. Even if the Board were to approve what has been provided to date it would be open, by Enbridge's own suggestion, to subsequent changes.[15]

> *Should the Board approve the cost allocation methodology proposals related to the Panhandle and St. Clair System, Parkway Station and Dawn Station as part of this proceeding, Enbridge Gas would use the approved methodologies in the preparation of the 2024 cost allocation study. The Board and intervenors could subsequently review and*

[13] I.IGUA.5

[14] I.SEC.6

[15] I.LPMA.2

comment on any component of the cost allocation study as part of the 2024 rebasing proceeding. A modest potential benefit to having the proposed cost allocation methodology changes reviewed and determined in this proceeding is that a participant in the rebasing proceeding would presumably have to show reasons why a further change is warranted, given the Board's recent review of the allocation methodologies.

As part of its next rebasing proceeding for 2024, Enbridge intends on filing a full system-wide cost allocation study that will review the allocation cost in both the EGD and Union Rate Zones, including costs at Parkway Station.[16] As such we would argue there is little value in the Board panel in this proceeding making a limited determination of the matter and one which may be of dispute in the next cost of service filing.

In our submission the cost allocation exercise undertaken by Enbridge in this proceeding dismissed in their entirety and without an opinion rendered as to its correctness.

eBilling

"*Enbridge Gas believes that it is appropriate to use eBill as the default for all scenarios where the customer has provided an email address*."[17] We disagree.

Enbridge explains that prior to the new policy the default billing option was a paper bill. Customers enrolling online via myAccount are now enrolled in eBill automatically. Previously a customer could select the eBill option themselves and they would be encouraged to do so as part of other customer interactions. These policies had by the end of 2018 led to 40% of customers adopting eBilling.[18]

However beginning in January of 2019 Enbridge began a two phase program to force customers onto eBills without their explicit consent. The Utility's eBill strategy included three core components: (1) change the default billing option from paper to eBill; (2) convert any customer for whom the Utility had an existing email to eBilling without their consent; (3) change the enrollment process such that eBilling would become the default option and eliminate the paper bill option from the online enrollment process. In the first phase customers involuntarily converted to eBill received also received a notice by mail. This practice was dropped in later phases of the program.

By November of 2019 this had let to an increase in eBill customers who now made up 58% of the total. However, a number of customers involuntarily switched faced late payments penalties because they were simply unaware of the change in practice. A large number of customers were unhappy with the Utility and believed they had been treated unfairly. Some of those customers contacted VECC.

[16] I.TCPL.1
[17] I.Pollution Probe.4
[18] Exhibit B, Tab 3, Schedule 1, page 17

Furthermore during this period when a customer contacted Enbridge Gas's call centre they were asked to provide the best contact information to get in touch with them regarding their account[19]. The subsequent providing of an email address would then enroll the customer in eBilling.

Enbridge's strategy was to presume that any email provided was sufficient to be used as an eBill address. No evidence was provided that would indicate that Enbridge disclosed to customers that a consequence of providing their email address they might be switched to a different method of billing. In any event a large number of customers neither had knowledge of, nor gave consent to, the move from paper to eBilling.

In the second phase beginning in March 2019 customers only received an email notice of the switch to eBilling. This inevitably led to customer confusion, especially for those that did not use mail regularly or used alternative emails for different functions. During this phase 103,359 customers were converted. The final phase was undertaken in October 2019, with 107,269 customers being converted in the same manner.

Based on the number of customer insisting on being switched back the paper bills one can only say the "customer satisfaction level" was abysmal.

Switched back to paper by phase LEGD	Total Converted	Switched back	%
LEGD			
Phase 1	147756	22421	15%
Phase 2	103359	24445	24%
Phase 3	107269	26845	25%
Total LEGD	**358384**	**73711**	**21%**
LUG			
Phase 1	171905	32661	19%

Source I.Staff.12

In 2019, ombudsman complaints related to eBill as a percentage of total complaints rose to 8.5% from 1.9% in 2018 in the EGD rate zone while in the Union Gas rate zone, related complaints rose from 0.6% in 2018 to 9% as shown in the table below.[20]

Table 5

	Ombudsman Complaints							
	2018 Total Complaints	**2018 eBill Complaints**	**eBill Complaints as a % of Total Complaints**	**2019* Total Complaints**	**2019* eBill Complaints**	**eBill Complaints as a % of Total Complaints**	**Total eBill Conversions (2019)**	**Complaints as a % of Total Conversions (2019*)**
EGD Rate Zone	8,177	153	1.9%	7,471	636	8.5%	331,480	0.2%
Union Rate Zones	5,004	32	0.6%	4,515	408	9.0%	171,905	0.2%

[19] I.VECC.15

[20] Exhibit B, Tab 3, Schedule 1, page 22

*January through November 2019

Not surprisingly the number of customers in good standing who fell into arrears subsequent to this change in policy soared as shown in the table below[21].

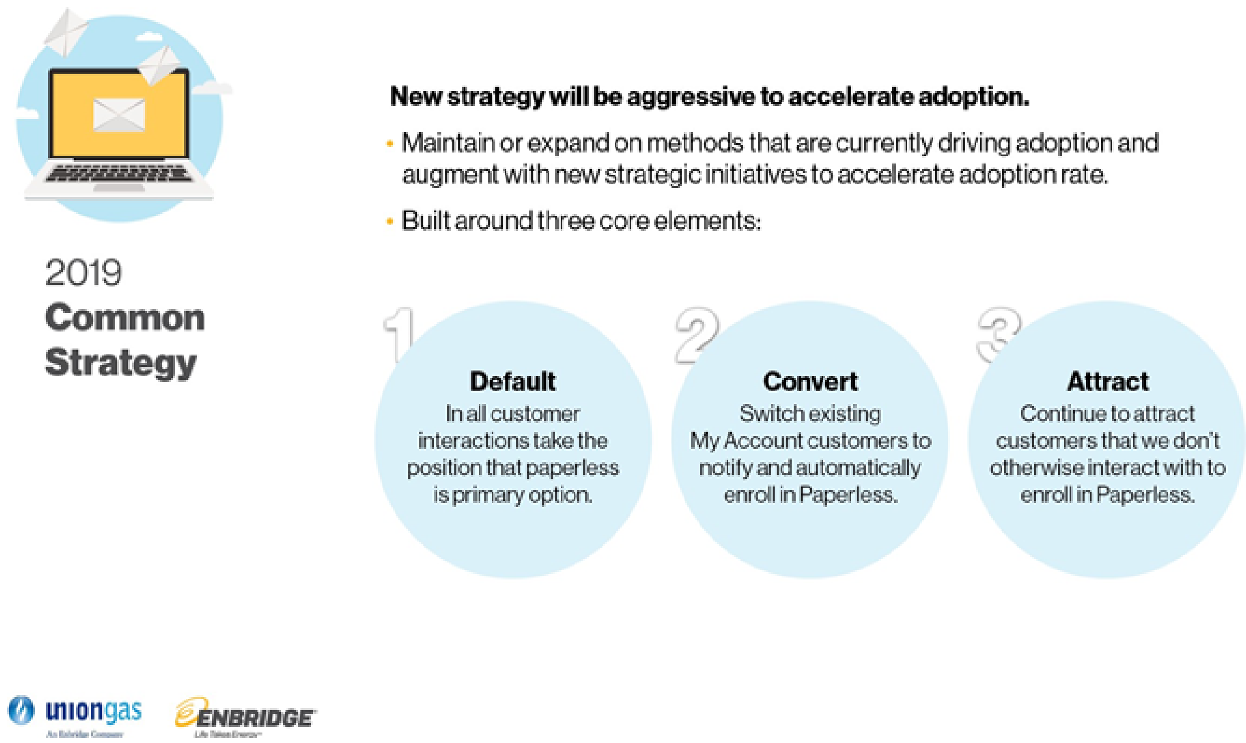
	Total	Phase 1	Phase 2	Phase 3
(A) fell into arrears	109,742	66,380	27,967	15,395
(B) received a collection/reminder notice	109,742	66,380	27,967	15,395
(C) received a disconnection notice	3,220	1,680	1,540	-
(D) were disconnected	684	214	470	-

As a result of the Board approved settlement Enbridge agreed to refund any late payments made by customers involuntarily moved from paper to eBilling. In total $289,240 was refunded across 33,948 customers in the Union Rate Zone and $446,242 across 60,370 customers in the Enbridge Rate Zone.

The entire exercise was carried out in order to realize cost savings. The cost difference between paper billing and eBilling is approximately $10 per customer per year[22]. During the deferred rate rebasing period these incremental revenues are of benefit only to shareholders. In what can only be described as "expected unregulated monopoly thinking" good service and consideration for the customer took a backseat to Utility's enrichment.

By their own admission the plan was "aggressive".[23] No detailed study was made of the desires of existing customers to change their billing format[24] . Nor was there a sophisticated or compassionate approach taken and consideration given to actually asking a customer whether they would like to change their billing method. In short, consumer respect demands opt-in, explicit consent, not automatic transfer to a new billing method, often by stealth.

[21] I.Staff.13
[22] Exhibit B, Tab 3, Schedule 1
[23] I.CCC.5, Attachment 1, page 3 of 6
[24] See I.VECC.16



The presumptive attitude of the Utility is summed up in their own evidence:

> "*Enbridge Gas's experience indicates that a customer who receives a traditional paper bill is much more likely to use more costly and cumbersome traditional methods to contact their utility for customer service. In contrast, customers that receive an eBill are much more likely to use more convenient and cost-effective digital services to meet their customer service needs*."[25]

"More convenient" and "cumbersome" being somewhat in the eye of the beholder. The Utility gave short shrift to the meaning of those words to its customers. To whom it was determined it was "more costly" is equally clear. The Utility – while the negative cost externalities (confusion, anger, missed payments, storage and management of electronic billing, including hard copy printing at home by customers) of this shift on consumers was not considered.

Enbridge Gas achieved approximately $3.7 million in savings in 2019 from converting customers to eBill. Given the implementation timeframes of this policy this is only a partial figure of the annual benefit to the Utility. Savings expected in 2020 are between $5.5 million and $6.0 million based on what was achieved in 2019. Further savings may be achieved depending on the additional adoption of eBill in 2020.[26]

Enbridge Gas's position is that no Board approval is required to change the default billing method. We disagree. To make the point in the extreme we ask the Board to consider how it

[25] Exhibit B, Tab 3, Schedule 1, page 16
[26] I.CCC.6

would react if the Utility determined on their own volition that bill payments could not be made by credit card. Of course that is not likely to happen but the point remains we think the Board would expect a utility to seek its approval for such a change. The matter is only one of degree – both the forma and the means of payment are matters of interest to the regulator. At a minimum one would expect the Utility to have notified the Board and so as to prepare its call centre for complaints or enquiries on the matter.

The means and form of payment of a regulated rate is just as integral to regulated rate making as is the methodology for setting it. The only reason it is not explicitly addressed in the regulatory process is that it seldom becomes an issue. Yet late payment issues are highly regulated and the Board has in the past spent considerable effort with (especially with respect to electricity distributors) on issues related to the closure on on-site payment facilities.

Enbridge Gas acknowledges that the Board has jurisdiction to establish rules related to a distributor's billing practices. However, as of the current date, no such rules have been established by the Board that are relevant to the issues raised by intervenors about eBill.

Similarly, Enbridge Gas acknowledges that the Board has jurisdiction to prescribe and make rules related to acceptable methods of bill format or payment. However, it is Enbridge Gas's position that the Company's actions to make eBill the default billing method are not in contravention of any orders or rules that the Board has made and/or implemented[27]. With respect that is beside the point.

New customers using the online portal are presented with no option for paper billing and must call in order to avail themselves to that option. Any existing customer who is receiving an eBill and wishes to switch to paper bill also needs to call Enbridge Gas's contact centre.

VECC's positon on the matter is clear – the customer should have a clear choice and therefore:

1. Paper billing should remain the standard billing option and until such time as the Board determines otherwise
2. There should be no surcharge for a paper bill (Enbridge does not propose one at this time). Nor should there be any charge for switching back to a paper bill, nor for the delivery of future paper bills.
3. On line account setup should explicitly allow an option to select between paper or eBilling.
4. A customer should be able to change their billing option on line and at any time.
5. Any customer involuntarily converted to eBills (i.e. without explicit opt-in consent) should be contacted by Enbridge by telephone to confirm their billing choice.

We note that Enbridge plans to amalgamate the two existing CIS systems into one by the end of 2021. The Board should, in our submission, inform Enbridge that any online account setup must allow for customers to explicitly choose their billing option.

[27] I.VECC.23

Finally VECC would note two things. The first is that we do not take a position against eBilling per se. It can be a convenient and less costly option. The unusual times have shown the importance of carrying out e-commerce. Nevertheless, our positon is that customers should be able to make informed choices, especially when there is a change in ongoing practice.

VECC always encourages dissatisfied customers to contact the Ontario Energy Board (and it successor). Given the level of customer dissatisfaction we were somewhat surprised that the Board's call centre had not identified this issue. This may have simply been because some customers are unaware of the Board's resources. Of more concern would be if the Board's processes did not provide a means for this concern to be heard as part of a Board proceeding. That would be unfortunate given the emphasis it has placed on customer engagement.

Unaccounted for Gas Report

EGI is not seeking any direct relief from the Board with respect to its UFG Report. And the Utility states is has an ongoing process to identify and standardize practices to better monitor and manage UFG. However there is little evidence as to precisely what actions it is taking in this regard.

While no direct relief is being sought the matter is one importance to ratepayers. Any variance between actual and forecast (i.e., OEB-approved) UFG volumes is recorded in the Unaccounted for Gas Variance Account (UFGVA) and cleared to customers as part of the annual disposition of all deferral and variance account balances.

Both the legacy Enbridge and Union rate zone have had significant variances as between its forecast and actual UFG amounts[28].

Legacy EGD Historical Unaccounted for Gas (CEB approved vs. Actual)

Calendar Year	Actual	OEB Approved	OEB Approved vs Actual
2014	135,380	77,660	-43%
2015	88,438	81,519	-8%
2016	133,112	84,766	-36%
2017	93,077	98,279	6%
2018	142,086	106,077	-25%

[28] I.EP.26

Legacy Union Year	Actual	Budget	Difference
2013	113,996	70,253	62.3%
2014	97,108	77,325	25.6%
2015	54,407	75,536	-28.0%
2016	131,588	78,340	68.0%
2017	108,901	89,851	21.2%
2018	136,447	79,180	72.3%

These tables demonstrate the material impact of UFG variances and the inability of the Utility to accurately forecast this item or the purpose of rate setting. The asymmetrical nature of the variances might also lead parties to question whether variance recovery for this issue is in the interest of ratepayers. The amounts of monies at play with respect to UFG and its variance from forecast are not insignificant as shown in the table below[29].

	Legacy Union Gas		**Legacy EGD**	
Year	**UFG $CDN**	**Cumulative UFG $CDN**	**UFG $CDN**	**Cumulative UFG $CDN**
2008	$56,241,846	$56,241,846	$13,398,496	$13,398,496
2009	$55,998,867	$112,240,713	$21,848,079	$35,246,575
2010	$17,263,561	$129,504,274	$17,692,816	$52,939,392
2011	$8,028,301	$137,532,575	$21,637,477	$74,576,869
2012	$12,902,646	$150,435,221	$15,478,819	$90,055,688
2013	$22,631,943	$173,067,164	$17,899,100	$107,954,787
2014	$18,429,387	$191,496,551	$27,615,027	$135,569,814
2015	$10,531,568	$202,028,118	$18,534,398	$154,104,212
2016	$18,510,324	$220,538,442	$22,368,047	$176,472,259
2017	$15,707,067	$236,245,509	$16,570,655	$193,042,914

[29] I.Pollution Probe.5

Under the current regime the Utility has no incentive to actively manage the issue as it is held whole regardless of actual events. In fact this very concern has been articulated in other UFG studies[30]:

> *One concern of commissions is that utilities may have a weak incentive for managing LAUF gas. This problem especially exists whenever a utility is able to pass through LAUF-gas costs to their customers with minimal regulatory scrutiny. As discussed in Part IV, several survey respondents stated that utilities have little or even no incentive to mitigate LAUF gas. Whether or not these observations are valid or even represent a commission's position, the responses do indicate the perception of an incentive problem. Some commissions have tried to elicit better utility performance through explicit incentive mechanisms or the capping of LAUFgas costs recoverable from customers. Most commissions implicitly have taken the position that it is easier to spread the costs of LAUF gas across all customers than to burden utility shareholders with those costs. The outcome creates little motivation for utilities to control LAUF gas. It also raises a "fairness" question of why utility customers should fully shoulder the burden of costs that are difficult to justify, let alone measure with reasonable accuracy.*

The ScottMadden Report found that the primary sources of UFG for the legacy companies include physical losses, retail meter variations, and gate station meter variations. A comparison of these sources is shown in the table below.[31]

Sources of UFG	*Connecticut PURA Report*	*ATCO Pipelines North*	*SoCalGas and SDG&E*	*Legacy Union*	*Legacy EGD*
Physical Losses	**0.8% – 13.8%**	**8.0% – 10.0%**	**14.0% – 17.0%**	**30.2%**	**18.1%**
Measurement Errors	**10.3% – 16.7%**	**60.0% – 80.0%**	**60.0% – 64.0%**	**13.1%**	**56.9%**
Accounting Issues or Adjustments	**71.5% – 88.0%**	**3.0% – 10.0%**	**5.0% – 8.0%**	**7.7%**	**3.5%**
Theft and Non-Registering Meters	**0.0% – 0.3%**	**2.0% – 6.0%**	**4.0% – 5.0%**	**2.6%**	**0.0%**

The Report "encourages" EGI to[32]:

- Identify and standardize "best practices" related to monitoring and managing UFG across the legacy Companies
- Document data, processes and studies related to monitoring and managing UFG and
- On a periodic basis:
    - Investigate the sources of Enbridge UFG (including the unknown / unexplained category)

[30] Exhibit I.FRPO.5, Attachment 1, NRRI, Lost and Unaccounted-for Gas: Practices of State Utility Commissions, June 2013, Page 20 of 106
[31] From I.EO.22 Attachment 1.
[32] Report on Unaccounted for Gas, Scott Madden, December 2019, page 9

- Research practices and initiatives at other gas utilities for monitoring and managing UFG and,
- Implement, as appropriate, new practices and initiatives to better monitor and manage UFG

It is somewhat disconcerting that not only is the Report rather vague as to what practices are employed by the Utility, but ScottMadden themselves appear to have little understanding themselves as to what precisely makes up industry "best practices."

Our concerns are not alleviated by the response of the Utility to the Study. While Enbridge states it has an ongoing process to identify and standardize practices to better monitor and manage UFG there is scant evidence as to what precisely this process encompasses[33]. Similarly the Report, while repeating the Utility line, makes no finding as how effective the Utility's employment of any current practice (best or otherwise) is.

We would also note the analysis is not explicit in its consideration of the issue UFG as pertains to heat content variability in natural gas. Nor did the Report not consider UFG arising specifically out of factors associated with gas storage injection and withdrawal.[34] It also did not examine the reasonableness of the cost allocation methodology for the disposition of variance accounts. In this regard we note that the former Enbridge and Union rate zones do not use identical methodologies and neither methodology attempts to draw correlations as between the cause of UFG and the party who pays for these costs[35].

Enbridge states that they expect to report on implementation progress in its 2022 Rates filing[36]. While they also say that there is an ongoing process to identify and standardize practices to better monitor and manage UFG there is scant evidence as to what precisely this process encompasses.

In our view the Study provides an insufficient basis to dispense with the matter. A more robust examination of UFG would have a more detailed examination of the sources of UFG, the methodologies for measuring UFG (given they are not now consistent) and a consideration of how UFG is forecast and any variances allocated to customer classes. In our submission the Board should alert Enbridge to the expectation that the matter be revisited in greater detail in the next amalgamated utility cost of service proceeding.

Reasonably Incurred Costs

VECC submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

[33] See for example the response to I. Pollution Probe.6
[34] I.EP.21
[35] See I.Pollution Probe.5
[36] I.EP.25