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Enbridge Gas Inc.
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February 25, 2021

BY RESS AND EMAIL

Ms. Christine Long
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board File No.: EB-2020-0091
Integrated Resource Planning Proposal
Undertaking Responses

Further to the undertaking responses filed by Enbridge Gas on February 18, 2021, enclosed please find the remaining undertaking responses taken from the technical conference held on February 10, 11, and 12, 2021 in the above noted proceeding.

Please note the response to Exhibit JT1.3 has been updated.

If you have any questions, please contact the undersigned.

Sincerely,

(Original Digitally Signed)

Adam Stiers
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)
M. Parkes (OEB Staff)
M. Millar (OEB Counsel)
EB-2020-0091 (Intervenors)

ENBRIDGE GAS INC.

Undertaking Response to FRPO

To provide the evidentiary or transcript reference to a process for stakeholders to raise alternate IRPAs and have them considered and addressed.

Response:

The process for stakeholders to raise alternative IRPAs is addressed as an objective of the proposed stakeholder approach in Enbridge Gas's Additional Evidence (Exhibit B) at paragraph 88 on page 39:

> Accordingly, the objectives of the IRP Stakeholder Engagement process will be to: (i) ensure planned resources will meet Enbridge Gas's obligation to safely and reliably deliver firm contracted demands; (ii) gather ample geographically-specific information such that IRPAs can be adequately reviewed and monitored; (iii) help inform the development of new or enhanced energy efficiency programming; and (iv) broadly inform Enbridge Gas's long-term strategic planning.
> (emphasis added)

It is further articulated in the Company's Reply Evidence (Exhibit C) at pages 13 and 14 within Section 3.0 Stakeholder Consultation/Engagement.

> Enbridge Gas acknowledges the importance of obtaining stakeholder input ahead of developing IRPAs to address identified system needs/constraints and of establishing a feedback loop to keep stakeholders (including municipal and government representatives, First Nations, end use customers from all sectors, customer and business associations) informed of its investments in and the impact of their respective input into the development of IRPAs.
>
> Enbridge Gas's proposed three component approach to stakeholder engagement, as set out in its Additional Evidence,[1] is meant to go beyond data collection in that it: (i) recognizes that each geographic area being consulted regarding an identified customer need or system constraint and relevant IRPA(s) will have unique attributes and stakeholders;[2] and (ii) seeks to solicit concrete input for Enbridge Gas planners to consider when assessing alternatives to resolve identified system capacity needs/constraints, through engagement with members of the public that are expected to be directly impacted.
> (emphasis added)

[1] Enbridge Gas Additional Evidence, Exhibit B, para. 89.
[2] Examples of which may include local chambers of commerce and boards of trades and their members, local businesses owners and associations, and local LDC's.

Additionally, Mr. Stiers provided an example of how an alternate IRPA could be brought forward on the proposed Stakeholder Day, as part of Component 2 of Enbridge Gas's proposed Stakeholder process, during his testimony in the Technical Conference on February 10, 2021:[3]

> And so in an effort to put forward a process that is reasonable and efficient, the company has suggested that what is appropriate is for it to focus on identifying the system constraints, as you stated, as it normally does in the normal course of business, and then subsequently to reflect on any input from external parties that it has through existing communication channels, so component one of our stakeholdering process. And then to consider using the IRP assessment process that we have set out in Exhibit B.
>
> Thus, various IRPAs might be reasonable or viable for serving that need. So the company expects that all along this process, it will take into account the input of stakeholders at that first early stage. It will be based on what we received already, but then we do expect that stakeholders will have an early and frequent opportunity to pose questions and provide comments on the decisions that the company has made.
>
> And so, following the identification of system constraints in our asset management plan, we would make the asset management plan public as part of our annual rates proceedings, and stakeholders would have an opportunity at its annual stakeholder day shortly after to pose questions and understand the decisions that the utility has made and to provide input on those, and all of that we intend to record.
>
> So beyond that, we also expect that we will file annual IRP reports and that we will, at the time we make an IRP application to the board, we would in each of those instances also be in a position to explain the decisions that we've made. And so we don't think it would be efficient for us to have additional, let's say, process aside from that.

Mr. Stiers went on to state:[4]

> I am letting you know our intentions going forward are to also hear at the -- for example, at the stakeholder day --from stakeholders, from people in affected geographic locations where a system constraint has been identified, and from parties, <u>whether or not they think there are other viable IRPAs that the utility should consider. Now, some of those we may have already assessed and considered and we may be prepared to speak to on the day or to provide follow-up on in fairly short order. I do foresee that there might be an instance where new IRPAs that were not necessarily considered could also surface, and we would give those consideration as well.</u> That's the purpose of the stakeholdering.
> <u>(emphasis added)</u>

[3] EB-2020-0091 OEB Technical Conference Transcript, February 10, 2021, pp. 12-14.
[4] EB-2020-0091 OEB Technical Conference Transcript, February 10, 2021, pp. 64-65.

After further discussion during his testimony in the Technical Conference on February 12, 2021, Mr. Stiers concluded:

> I think what we set out is up to ten years in advance identifying a system constraint and as quickly as possible, wrapping our heads around what that constraint is and what the appropriate means might be to resolve that constraint from both a facility and a non-facility standpoint, and as immediately as possible looking to consult on what we think makes sense with the public, with First Nations, with parties. We see that as quite timely consultation.

UPDATE

Enbridge Gas is committed to public participation and receiving formal written suggestions and questions that will be answered by the Company and posted online (e.g. as part of its website). As part of its response to OEB Staff interrogatories, the Company stated:[5]

> Enbridge Gas recognizes that as part of these activities, participating stakeholders and Indigenous communities could provide additional insight into IRPAs that the Company did not consider or was unaware of. For example, the stakeholder plan will seek to gain understanding from stakeholders and Indigenous communities on customer growth expectations and willingness to participate in potential demand response programming; economic activity and growth; low carbon alternative opportunities; energy efficiency and conservation potential opportunities; new and emerging technological advances.

Enbridge Gas has put forward an Ontario focused stakeholder engagement model that reflects the vast differences in geography, climate, customer type and demands in communities served by the Company across the province. As discussed in the Company's interrogatory response at Exhibit I.STAFF.9 b), Enbridge Gas's proposed stakeholder engagement strategy has been influenced by and is similar in many respects to the engagement initiatives conducted by Ontario's IESO as part of its Integrated Regional Resource Plan ("IRRP") processes. The IESO stakeholder model has evolved in recent years in response to a cycle of continuous improvement, informed by government policy and the OEB, and is used to engage with stakeholders across a similarly complex energy system.[6] Currently the IESO uses a regional electricity network model that allows for more targeted discussions to be conducted in five specific regions.

Initially, as part of Component 2 of its proposed Stakeholder Outreach strategy, Enbridge Gas proposed to discuss the AMP and any associated IRPA's during an annual Stakeholder Day following the filing of the annual update to the AMP. Following the Technical Conference and the Presentation Day in this proceeding the Company reflected upon whether it would be appropriate, efficient and helpful to expand upon the

[5] Exhibit I.STAFF.9 a).
[6] Exhibit I.GEC.5 b).

proposed annual Stakeholder Day. Enbridge Gas has determined that Component 2 of its stakeholder engagement process could also benefit from this regional focus. Therefore, the Company now proposes to separate the projects identified in its annual update to the AMP (including IRPAs) into similar regional areas in support of conducting multiple targeted annual Stakeholder Days (one in each region annually where projects have been identified). In establishing regions for these purposes, Enbridge Gas will attempt to mimic the regional breakdown of the IESO Regional Electricity Networks wherever appropriate.[7]

[7] https://www.ieso.ca/en/Get-Involved/Regional-Planning/Electricity-Networks/Overview

ENBRIDGE GAS INC.

Undertaking Response to SEC

To confirm whether the 20-year plan has been provided, and in what future proceeding it might be provided.

Response:

Enbridge Gas has provided 20-year demand forecast information as part of the following recent leave to construct ("LTC") proceedings:

- EB-2018-0306 – Stratford Reinforcement;[1]
- EB-2018-0013 – Kingsville Transmission Reinforcement Project;[2] and
- EB-2016-0186 – Panhandle Reinforcement Project.[3]

The Company expects that it may provide 20-year demand forecasts, where relevant, in future LTC proceedings, subject to the need to protect commercially sensitive customer information.

[1] EB-2018-0306, Application, Schedule 7; EB-2018-0306, Responses to Interrogatories, SEC.3.
[2] EB-2018-0013, Exhibit A, Tab 6, Table 6-1.
[3] EB-2016-0186, Exhibit A, Tab 5, pp. 11-12; EB-2016-0186, Exhibit B.FRPO.13.

ENBRIDGE GAS INC.

Undertaking Response to ED

To advise whether an IRP analysis has been undertaken, whether IRP alternatives have been screened out, and whether the project is driven all or in part by forecast demand growth.

Response:

Given that Enbridge Gas's IRP Proposal is currently before the Board and thus, an IRP Framework for the Company remains outstanding at the time of this submission, none of Enbridge Gas's proposed IRP assessment or evaluation processes have been completed for the future forecasted projects listed on page 34 of the Company's 2021-2025 Asset Management Plan. For discussion of which of the projects contained therein is driven by growth please see the response at Exhibit I.STAFF.8.

ENBRIDGE GAS INC.

Undertaking Response to GEC

To provide what additional information would be provided in the AMP specifically if an IRP is chosen, and what specific information will now be shown in future AMPs where you've not selected an IRP and you have gone for a facility.

Response:

Enbridge Gas will provide in successive versions of the AMP, evidence on where each identified need is in the planning process. A conceptual example of that information is shown Table 1 below.

Table 1

	IRP Binary Screening Completed? *(Yes, No)*	**IRP Stage 1 – IRPA Assessment Completed?** *(Yes, No, n/a)*	**IRP Stage 2 - Economic Analysis Completed? Results?** *(Yes, No, n/a)*	**Contains IRPA(s)?** *(Yes, No, Description of IRPA(s))*
Project 1				
Project 2				
…				
Project n				

Enbridge Gas is proposing that Table 1 that will feature in the AMP, will show all projects and whether they have been screened in or out. Further, where a project has an IRPA solution (or portfolio of IRPAs) an Investment Summary Report will be completed and included in the AMP. Where a project or need is screened out, Enbridge Gas notes that it will be done either on the basis of an objective binary screening criteria established by the Board as part of the IRP Framework, or on the basis of some insight regarding the Company's obligation to safely and reliably meet the needs of its customers. Enbridge Gas notes that the AMP continuously evolves and so the there are many opportunities for changes over time.

ENBRIDGE GAS INC.

Undertaking Response to GEC

To provide AMP data 10 years out, if available, or shorter periods, as available.

Response:

Enbridge Gas has not historically produced a long-range forecast in any format that would meet the intent of the undertaking. Up to 2019, Enbridge Gas operated as two separate entities. For each of the legacy utilities, and for Enbridge Gas, a demand forecast is filed annually for the following year as noted in the response at Exhibit I.OSEA.10, and clarified in the response at Exhibit JT1.13.

A 10-year customer forecast is filed in the Asset Management Plan and has been filed as part of multiple rates cases, but that process only started in around 2018.

The Gas Supply Plan (and Annual Updates) was filed for 2019, 2020 and 2021, and it contains some of the information that parties are seeking.

ENBRIDGE GAS INC.

Undertaking Response to SEC

To provide whatever document would have been provided to the board of directors to make them aware of this application.

Response:

Please see Attachments 1 and 2 to this response which contain notes about Enbridge Gas's IRP Framework proceeding and related activities for the Company's Board of Directors and the Enbridge Inc. ("Enbridge") Board of Directors, respectively. Enbridge Gas has redacted the remaining content in these memoranda and presentations as it bears no relevance to the development of an IRP Framework for Enbridge Gas.

<u>July 14, 2020: Operational Report to Enbridge Inc. Board of Directors</u>

Growth Proceedings

• 14 Leave to Constructs totaling ~$590M to be filed in the remainder of the year

• Several proceedings on low carbon growth underway:

- Integrated Resource Planning ("IRP") assessing non-pipe solutions i.e. conservation: Procedural order awaited
- Voluntary Renewable Natural Gas ("RNG") Program: Decision expected Q3
- Low Carbon Energy Project (Hydrogen Blending): OEB ordered TSSA to file broader safety issues associated with the Project 7

<u>July 22, 2020: Operational Report to Enbridge Gas Inc. Board of Directors</u>

Integrated Resource Planning ("IRP"): The OEB requires EGI to consider non-pipe alternatives as part of LTC proposals. The purpose of this proceeding is to establish a framework for including IRP alternatives once need for infrastructure is identified. IRP alternatives include Demand Response, Enhanced Targeted Efficiency Programs; CNG, and Low-Carbon/Non-Gas Solutions. The Board is in the process of establishing the Issues List for this proceeding. The timing and next steps are yet to be determined.

<u>October 27, 2020: Operational Report to Enbridge Inc. Board of Directors</u>

Low Carbon Growth Proceedings

- Integrated Resource Planning – EGI filed further evidence on October 15 on a suitable framework for assessing non pipe solutions to meet growth in peak demand
- Low Carbon Energy Project (Hydrogen Blending) – OEB decision expected prior to year end on introducing hydrogen to a small closed-loop section of the distribution system in Markham with blending of up to 2% for approximately 3,600 customers.

<u>October 27, 2020: Operational Report to Enbridge Gas Inc. Board of Directors</u>

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further evidence on October 15 on a suitable framework for assessing non pipe solutions to meet growth in peak demand. Other parties are expected to file evidence in November 2020. The proceeding will continue into 2021.

February 2, 2021: Operational Report to Enbridge Inc. Board of Directors

Low Carbon Growth Proceedings

- Integrated Resource Planning proceeding will set a framework to assess the cost effectiveness of non-pipe solutions to meet peak demand growth. GDS proposed a framework that would rate-base non-pipe solutions. Decision expected in Q2
- Low Carbon Energy Project (Hydrogen Blending) – OEB approved our pilot program to blend up to 2% hydrogen in NG stream for approximately 3,600 customers in Markham – in service expected in Q2.

February 2, 2021: Operational Report to Enbridge Gas Inc. Board of Directors

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further evidence on October 15 on a suitable framework for assessing non pipe solutions to meet growth in peak demand. Other parties filed evidence in November 2020. An oral hearing is scheduled for March, 2021.

July 22, 2020

CONFIDENTIAL

ENBRIDGE GAS INC.
BOARD OF DIRECTORS

Re: Operational Update Report

This memo is a supplement to the attached quarterly Gas Distribution and Storage Commercial and Operations presentation to the Enbridge Inc. Board of Directors dated July 14, 2020.

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]

Gas Distribution and Storage

Enbridge Inc. Board of Directors

July 14, 2020

ENBRIDGE

[redacted]

Growth Proceedings

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- Several proceedings on low carbon growth underway:
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ENBRIDGE

October 27, 2020

CONFIDENTIAL

ENBRIDGE GAS INC.
BOARD OF DIRECTORS

Re: Operational Update Report

This memo is a supplement to the attached quarterly Gas Distribution and Storage Commercial and Operations presentation to the Enbridge Inc. Board of Directors dated October 27, 2020.

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Targeted Efficiency Programs; CNG, and Low-Carbon/Non-Gas Solutions. EGI filed further evidence on October 15 on a suitable framework for assessing non pipe solutions to meet growth in peak demand. Other parties are expected to file evidence in November 2020. The proceeding will continue into 2021.

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Gas Distribution and Storage

Board of Directors
October 27, 2020

ENBRIDGE

[redacted]

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ENBRIDGE

February 2, 2021

CONFIDENTIAL

ENBRIDGE GAS INC.
BOARD OF DIRECTORS

Re: Operational Update Report

This memo is a supplement to the attached quarterly Gas Distribution and Storage Commercial and Operations presentation to the Enbridge Inc. Board of Directors dated February 2, 2021.

[redacted]

[redacted]

	[redacted]			[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]

Gas Distribution and Storage

Board of Directors
February 2, 2021

[redacted]

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Low Carbon Growth Proceedings

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2020 Strategy Update
Gas Distribution & Storage

Board Planning Session
July 22, 2020

[redacted]

ENBRIDGE

[redacted]

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- [redacted]

[redacted]

- [redacted])
- Build IRP into planning process and identify new assets to own and operate
- [redacted]

- [redacted]

[redacted]

[redacted]

- [redacted]

[redacted]

ENBRIDGE GAS INC.

Undertaking Response to Pollution Probe

To make best efforts to provide IRP screening documentation.

Response:

To date, Enbridge Gas has not used a formal IRP screening tool or prescribed process to evaluate IRP alternatives for facilities projects. The steps that Enbridge Gas has taken to consider IRP alternatives to specific facilities have been described in associated applications and proceedings for leave to construct (e.g., Cherry to Bathurst Replacement Project – EB-2020-0136; and London Lines Replacement Project – EB-2020-0192).

ENBRIDGE GAS INC.

Undertaking Response to FRPO

(a) To provide numbers for the Enbridge Gas Distribution territory in relation to the updated response to FRPO 49.

(b) To respond to the following question: with the decrease in interruptible load seen here and expected in the EGD rate zone, is it time to review if the interruptible rates have sufficient economic incentive to be useful as demand response in the IRP framework?

Response:

a) The interruptible demand in the EGD rate zone is as follows:

Table 1

10^3m^3/day	**Contracted**
Winter 2013/2014	4,887
Winter 2020/2021	3,040

b) The appropriate time to consider changes to rate design is as part of a rebasing application where the impact of rate design changes can be made on a revenue neutral basis. Enbridge Gas will review the pricing of its services, including interruptible distribution services, as part of its 2024 rebasing application and evidence.

The price differential between firm and interruptible services is not the primary driver for customers' preference for firm service. The cost advantage of interruptible natural gas distribution service is generally outweighed by other key factors including alternative fuel prices, the on-going cost of owning and operating alternative fuel systems, the reliability and availability of alternative fuel sources during sustained curtailments, and the risk of business interruption impacting production.

Please also see Enbridge Gas's Additional Evidence at Exhibit B, p. 27, and its responses at Exhibit I.STAFF.15, and at Exhibit I.GEC.24, for further discussion of interruptible services/rates.

ENBRIDGE GAS INC.

Undertaking Response to GEC

To provide a template that works with both facilities and non-facilities and mixes of facilities and non-facilities.

Response:

Please see the response at Exhibit JT2.15.

ENBRIDGE GAS INC.

Undertaking Response to GEC

To clarify the proportion of identified projects which will now fall under the increased LTC threshold, by percentage of projects and percentage of capital spending.

Response:

There are over two thousand (2,000) projects in the Company's Asset Management Plan ("AMP"). Establishing a scope that requires all of those projects to be considered for IRP analysis in the early stages of Enbridge Gas's implementation of an IRP Framework would not be reasonable or efficient as it would require exponential incremental administrative burden to be borne by ratepayers for limited value. Further, the Company doubts that such a task would be technically feasible.

Following its review of review of the Board's recent Decision and Order for the London Lines Replacement Project (EB-2020-0192), Enbridge Gas has reconsidered whether its singular focus upon growth projects for IRP purposes remains appropriate. Enbridge Gas continues to believe that that IRP will most effectively be applied to projects where growth is the main driver. However, the Company acknowledges that for large pipeline replacement and relocation projects, there may be opportunities to reduce the size of the replacement and these too should be considered for IRP in the future. The Company does not believe that IRP will be appropriate for smaller scale pipeline replacement projects (less than $10 million cost), as the cost savings that would result from downsizing pipeline size will not be significant enough to support consideration of IRP alternatives.

To provide clarity with regard to the nature of projects that are most relevant for IRP consideration, Enbridge Gas proposes to add one additional binary screening criteria, as follows:

vi. Pipeline Replacement and Relocation Projects – if a project is being advanced for replacement or relocation of pipeline, and the cost is less than $10 million, then that project is not a candidate for IRP analysis.

Based on these criteria, Tables 1 and 2 below have been developed to reflect the percentage of Enbridge Gas's total capital spending that could feasibly advance beyond the binary screening process to the proposed IRPA evaluation process. However, in order to provide a representative view that might apply in future years, Tables 1 and 2 below do not take into account the Company's proposed Timing criterion (required 3-year lead time). As seen in Table 1 below, 27% of forecasted capital investments could advance beyond the Company's proposed binary screening process.

Table 1

	2021	2022	2023	2024	2025	Total
Main Replacements & Relocations > $10M	$ 206,228,091	$ 174,849,057	$ 106,671,087	$ 161,012,110	$ 127,225,506	$ 775,985,851
System Reinforcement (all)	$ 92,412,034	$ 289,881,388	$ 159,168,683	$ 177,997,863	$ 208,094,403	$ 927,554,370
Total	$ 298,640,125	$ 464,730,445	$ 265,839,770	$ 339,009,973	$ 335,319,908	$ 1,703,540,220
EGI Capital Spend	$ 1,270,478,059	$ 1,405,978,079	$ 1,163,427,104	$ 1,352,601,964	$ 1,111,519,734	$ 6,304,004,942
IRP Eligible Spend as a % of Total	24%	33%	23%	25%	30%	27%

It is also relevant to understand the number of unique projects that are represented in the overall capital forecast for each category, as it informs the amount of effort required to perform the binary screening exercise and then to undertake the two-stage IRPA evaluation process.

Table 2 below sets out the number of projects from the 2021-2025 AMP that are included in Table 1 above. Note that the AMP does not provide granular project-level information about discrete projects for all later years (in some cases the Programs in the AMP are not yet broken down into projects for later years - for example projects anticipated to be driven by changes to Class Location or Municipal Requirements). As a result, the number of projects indicated in Table 2 will change over time.

Table 2

Main Replacements & Relocations > $10M	20
System Reinforcement (all)	168
Total	188
Number of Projects in the AMP	2114
% of Projects	9%

ENBRIDGE GAS INC.

Undertaking Response to FRPO

To provide details of the steps or the activities within the four-year timeline that it will take Enbridge to design, plan, seek OEB approval for, and construct an LTC facilities project.

Response:

In its response to interrogatories at Exhibit I. FRPO.17, the Company stated

> "…based on Enbridge Gas' current estimates of scheduling, the Company would require a minimum term of approximately 4 years to design, plan, seek OEB approval for and to construct."

This approximate timeline can vary, depending on the nature of specific projects and upon a variety of external factors at the time (e.g. environmental, regulatory etc…).

If a facility alternative is determined to be the preferred solution, the timelines associated with the activities set out in Table 1 will determine the amount of time required to design, plan, seek OEB approval for and to construct the project.

Table 1

Activity	**Approximate Duration**
Detailed design and engineering	3-6 months
Environmental assessment and archaeological studies	9-12 months
Regulatory leave to construct process	9-12 months
Stakeholder consultation and land acquisition (including expropriation)	Ongoing from EA 9-12 months *(expropriation)*
Permit application process	Ongoing from LTC filing
Prime contractor bid process and award contract	Ongoing throughout
Long lead time material order and procurement process	Ongoing throughout
Construction	6-9 months
Commissioning	1-2 months

While certain of these activities can partially overlap (occur in parallel to an extent), each activity is somewhat unique for each project and the completion of these activities has historically taken approximately 4 years to complete.

ENBRIDGE GAS INC.

Undertaking Response to Anwaatin

To advise as to whether any changes need to be made to paragraph 74 of Exhibit B to reflect what's set out in IR STAFF 22; to clarify as necessary.

Response:

No changes are required to Exhibit B, paragraph 74 as it is consistent with the information provided in the response at Exhibit I.STAFF.22.

The response at Exhibit I.STAFF.22 discusses Enbridge Gas's proposed treatment of three categories of IRP costs: (i) Incremental IRP Administrative Costs to be treated as an O&M cost; (ii) IRPA Project Costs to be capitalized to rate base; and (iii) Ongoing IRP Operating and Maintenance Costs to be treated as an O&M cost.

Pre-filed evidence Exhibit B, paragraph 74 proposes that IRPA Project Costs be treated in the same manner as the costs for facility expansion/reinforcement projects they defer, avoid or reduce and capitalized to rate base. This treatment is consistent with the second category of IRP costs, IRPA Project Costs, in Exhibit I.STAFF.22.

Enbridge Gas expects that the treatment of costs may evolve over time as experience is gained and that future IRPA applications to the Board will contain more specific details regarding the IRPA-specific cost recovery proposed or incentive/reward sought.

ENBRIDGE GAS INC.

Undertaking Response to EP

To provide an illustrative example of the evaluation process that Enbridge would use to compare a hypothetical transmission project with an alternative where a demand response program is implemented that decreases the size of the transmission project by 20 percent.

Response:

Please see Attachment 1 for the requested illustrative example.

Illustrative Demand Response vs Pipeline Example

	Pipeline				IRPA					
	Pipeline NPV	**Capacity Created (m3/hr)**	**NPV per Unit ($/m3/hr)**	**Stage 1 PI**	**Demand Response NPV**	**80% Pipeline NPV**	**Net IRPA NPV**	**Capacity Created (m3/hr)**	**NPV per Unit ($/m3/hr)**	**Stage 1 PI**
	(a)	(b)	(c) = (a) / (b)		(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) / (g)	
Stage 1	AAA	100	A.AA	PI	XXX	AAA	AXA	100	A.XA	PI
Stage 2	BBB	100	B.BB	n/a	YYY	BBB	YBY	100	Y.BY	n/a
Stage 3	CCC	100	C.CC	n/a	ZZZ	CCC	ZCZ	100	Z.CZ	n/a
Total	ABC	100	A.BC	n/a	XYZ	ABC	XYC	100	X.YC	n/a

Notes:

1 DCF analysis that would be used to evaluate the NPV of a typical Demand Response program that decreases the size of a transmission project by 20 percent.

2 Evaluation horizon of 40 years.

3 Calculated NPV is divided by capacity created to determine the cost per unit of capacity.

4 The test will be evaluated at each stage as well as the total of all stages.

Stage 1 DCF Analysis

Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Incremental Revenues	Incremental transmission revenue received by Utility accounting for IRPA impact. Does not include gas commodity revenue.	XXX	XXX	XXX	XXX	XXX	XXX
Avoided Commodity/Fuel Costs		-	-	-	-	-	-
Avoided O&M & Municipal Tax	Lower municipal taxes from decreased size of transmission project.	XXX	XXX	XXX	XXX	XXX	XXX
Total Benefits		XXX	XXX	XXX	XXX	XXX	XXX
Costs:							
Incremental O&M	Includes Demand Response program costs (e.g. enrollment rebates, customer incentives).	XXX	XXX	XXX	XXX	XXX	XXX
Incremental Municipal Tax		-	-	-	-	-	-
Incremental Commodity/ Fuel Costs		-	-	-	-	-	-
Incremental Income Tax	Income tax effect from avoided municipal taxes and incremental O&M.	XXX	XXX	XXX	XXX	XXX	XXX
Total Costs		XXX	XXX	XXX	XXX	XXX	XXX
Net Operating Benefit/Cost		XXX	XXX	XXX	XXX	XXX	XXX
Capital							
Avoided Infrastructure Costs	Lower capital costs from decreased size of transmission project.	(XXX)	(XXX)	-	-	-	-
Change in Working Capital		-	-	-	-	-	-
Total Capital		(XXX)	(XXX)	-	-	-	-
CCA Tax Shield							
CCA Tax Shield	Lower CCA tax shield resulting from avoided infrastructure costs.	XXX	XXX	-	-	-	-
Net Present Value							
PV of Operating Cash Flow		XXX	XXX	XXX	XXX	XXX	XXX
PV of Capital		XXX	XXX	-	-	-	-
PV of CCA Tax Shield		(XXX)	(XXX)	(XXX)	(XXX)	(XXX)	(XXX)
Total NPV by Year		XXX	XXX	XXX	XXX	XXX	XXX
Project NPV	Discounted using a discount rate equal to the Utility's incremental after-tax cost of capital.	**XXX**					

Stage 2 DCF Analysis

Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Avoided Infrastructure Costs		-	-	-	-	-	-
Avoided Commodity/Fuel Costs	Reduced costs incurred by customer due to annual reduction in consumption. Would not include load shifting (i.e. lower peak day consumption offset by higher consumption during off peak periods).	YYY	YYY	YYY	YYY	YYY	YYY
Avoided GHG Emission	Reduced Federal Carbon Charge associated with Avoided Commodity/Fuel Costs identified above.	YYY	YYY	YYY	YYY	YYY	YYY
Total Benefits		YYY	YYY	YYY	YYY	YYY	YYY
Costs:							
Incremental Customer Costs	Costs incurred by customer net of any rebates/incentives received from the Utility.	YYY	YYY	YYY	YYY	YYY	YYY
Incremental Commodity/ Fuel Costs	Costs incurred by customer due to the use of an alternative fuel to mitigate reduced use of natural gas.	YYY	YYY	YYY	YYY	YYY	YYY
Incremental GHG Emissions	Federal Carbon Charge associated with use of an alternative fuel identified above if applicable.	YYY	YYY	YYY	YYY	YYY	YYY
Total Costs		YYY	YYY	YYY	YYY	YYY	YYY
Net Operating Benefit/Cost		YYY	YYY	YYY	YYY	YYY	YYY
Net Present Value							
Total NPV by Year		YYY	YYY	YYY	YYY	YYY	YYY
Project NPV	Discounted using a societal discount rate (currently 4%).	**YYY**					

Stage 3 DCF Analysis

Illustrative Demand Response Example

Project Year ($000's)	**Notes / Examples**	**Project Total**	**1**	**2**	**3**	**.....**	**40**
Operating Cash Flow							
Benefits:							
Other External Non-Energy Benefits	Quantifiable benefits such as GDP impact and jobs created to be included. Current DSM assumption is that the societal benefit is 15% of identified customer benefits.	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Total Benefits		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Costs:							
Other External Non-Energy Costs	Unlikely to identify quantifiable societal costs associated with a Demand Response program.	-	-	-	-	-	-
Total Costs		-	-	-	-	-	-
Net Operating Benefit/Cost		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Net Present Value							
Total NPV by Year		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Project NPV	Discounted using a societal discount rate (currently 4%).	**ZZZ**					

Stage 1 DCF Analysis

Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	…..	40
Operating Cash Flow							
Benefits:							
Incremental Revenues	Incremental transmission revenue received by Utility. Does not include gas commodity revenue.	AAA	AAA	AAA	AAA	AAA	AAA
Avoided Commodity/Fuel Costs		-	-	-	-	-	-
Avoided O&M & Municipal Tax		-	-	-	-	-	-
Total Benefits		-	-	-	-	-	-
Costs:							
Incremental O&M	Incremental O&M to maintain pipeline.	AAA	AAA	AAA	AAA	AAA	AAA
Incremental Municipal Tax	Incremental municipal tax paid for pipeline.	AAA	AAA	AAA	AAA	AAA	AAA
Incremental Commodity/ Fuel Costs		-	-	-	-	-	-
Incremental Income Tax	Income tax effect from incremental revenue, municipal taxes, and O&M.	AAA	AAA	AAA	AAA	AAA	AAA
Total Costs		AAA	AAA	AAA	AAA	AAA	AAA
Net Operating Benefit/Cost		AAA	AAA	AAA	AAA	AAA	AAA
Capital							
Incremental Infrastructure Costs	Capital costs for new pipeline.	AAA	AAA	-	-	-	-
Change in Working Capital		-	-	-	-	-	-
Total Capital		AAA	AAA	-	-	-	-
CCA Tax Shield							
CCA Tax Shield	CCA tax shield associated with capital costs for new pipeline	AAA	AAA	-	-	-	-
Net Present Value							
PV of Operating Cash Flow		AAA	AAA	AAA	AAA	AAA	AAA
PV of Capital		AAA	AAA	-	-	-	-
PV of CCA Tax Shield		AAA	AAA	AAA	AAA	AAA	AAA
Total NPV by Year		AAA	AAA	AAA	AAA	AAA	AAA
Project NPV	Discounted using a discount rate equal to the Utility's incremental after-tax cost of capital.	**AAA**					

Stage 2 DCF Analysis

Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Avoided Infrastructure Costs		-	-	-	-	-	-
Avoided Commodity/Fuel Costs	Reduced costs incurred by customer associated with non-use of alternative fuels such as fuel oil, propane, electricity.	BBB	BBB	BBB	BBB	BBB	BBB
Avoided GHG Emission	Reduced Federal Carbon Charge associated with Avoided Commodity/Fuel Costs identified above if applicable.	BBB	BBB	BBB	BBB	BBB	BBB
Total Benefits		BBB	BBB	BBB	BBB	BBB	BBB
Costs:							
Incremental Customer Costs		-	-	-	-	-	-
Incremental Commodity/ Fuel Costs	Incremental natural gas costs incurred by customer.	BBB	BBB	BBB	BBB	BBB	BBB
Incremental GHG Emissions	Federal Carbon Charge associated with use of incremental natural gas identified above.	BBB	BBB	BBB	BBB	BBB	BBB
Total Costs		BBB	BBB	BBB	BBB	BBB	BBB
Net Operating Benefit/Cost		BBB	BBB	BBB	BBB	BBB	BBB
Net Present Value							
Total NPV by Year		BBB	BBB	BBB	BBB	BBB	BBB
Project NPV	Discounted using a societal discount rate (currently 4%).	**BBB**					

Stage 3 DCF Analysis

Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Other External Non-Energy Benefits	Benefits such as GDP impact, jobs created, and resiliency as back up energy source during power outages may be included.	CCC	CCC	CCC	CCC	CCC	CCC
Total Benefits		CCC	CCC	CCC	CCC	CCC	CCC
Costs:							
Other External Non-Energy Costs	No quantifiable societal costs have been included to date.	-	-	-	-	-	-
Total Costs		-	-	-	-	-	-
Net Operating Benefit/Cost		CCC	CCC	CCC	CCC	CCC	CCC
Net Present Value							
Total NPV by Year		CCC	CCC	CCC	CCC	CCC	CCC
Project NPV	Discounted using a societal discount rate (currently 4%).	**CCC**					

ENBRIDGE GAS INC.

Undertaking Response to EP

To inform us how more detail on how risks would be addressed during the evaluation of the baseline and IRPA's, such as risk tools and what tools might they use.

Response:

Enbridge Gas considers the following risk categories:

- **Employee and Contractor Health and Safety**: Level of injury or illness due to incident;
- **Public Health and Safety**: Level of injury and number of people impacted;
- **Environmental**: Breadth and severity resulting in environmental damage/impact;
- **Financial**: Level of financial impact;
- **Operational**: Length of time and breadth of impact on utility & transportation customers and diversion of resources; and
- **Reputational**: Level of media coverage, impact on customers, potential penalties or impact on ability to operate due to compliance issues.[1]

Figure 1 below provides an illustrative example to inform the Board and parties how Enbridge Gas might document risk related to baseline facilities and IRPAs going forward, subject to the establishment of an IRP Framework for the Company. Enbridge Gas expects that as the Company gains expertise deploying IRPAs it will be able to reevaluate the risk impacts of each IRPA in various situations.

Figure 1

Risk of IRPA relative to traditional facilities				
Significantly Better	Better	Neutral	Worse	Significantly Worse

	IRPA Examples				
Risk Category	Demand Response	Demand Response & AMI	CNG	EASHP	ETEE
Employee & Contractor H&S					
Public H&S					
Environmental					
Financial					
Operational					
Reputational					

[1] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, p. 58;
https://www.rds.oeb.ca/CMWebDrawer/Record/689895/File/document

ENBRIDGE GAS INC.

Undertaking Response to Anwaatin

To advise as to whether Enbridge has an updated expectation or forecast as to what percentage of its projects would be conducive to IRP, and whether directionally it is anticipated to be higher or lower than the 14 to 17 percent threshold.

Response:

Please see the response at Exhibit JT2.11. Please note that the estimate of projects conducive to IRP referenced in ICF's 2018 IRP Study was derived prior to the development of the Company's IRP Proposal, was limited to consideration of geo-targeted DSM, and reflected application of a growth rate threshold which is not included in Enbridge Gas's IRP Proposal.

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide ICF documentation about the Central Hudson Program.

Response:

Central Hudson's: (i) Non-Pipeline Alternatives Compliance Filing, dated June 21, 2019; (ii) Non-Pipeline Alternatives Annual Report for 2019 (dated December 2, 2019); and (iii) Non-Pipeline Alternatives Annual Report for 2020 (dated December 1, 2020), are set out in Attachment 1. These reports provide a status update on the following Central Hudson projects:

- **Transportation Mode Alternatives:** Designed for strategic abandonment of leak prone pipe through electrification where it is more cost effective than replacement and system reliability is not negatively impacted.

- **Load Growth-Based Projects:** These types of projects would be designed to manage locational constraints that are associated with peak demand.

December 2, 2019

Hon. Michelle L. Phillips
Acting Secretary
New York State Public Service Commission
Agency Building 3
Albany, NY 12223-1350

Re: Case 17-G-0460 - *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*; Non-Pipeline Alternatives Compliance Filing

Dear Secretary Phillips:

In compliance with the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan issued on June 14, 2018 in the above-referenced case, Central Hudson Gas & Electric Corporation hereby submits its Non-Pipeline Alternatives Annual Report.

Questions regarding this filing may be directed to Mark Sclafani at (845)486-5979 or msclafani@cenhud.com.

Respectfully submitted,

/s/*Paul A. Colbert*

Paul A. Colbert
Associate General Counsel
Regulatory Affairs

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	**Case 17-G-0460**

Central Hudson Gas & Electric Corporation's Non-Pipeline Alternatives Annual Report

December 2, 2019

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

Table of Contents

Background

Non-Pipeline Alternatives ("NPAs") are projects designed to displace the need for traditional gas infrastructure investment. Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") proposed to incorporate NPA projects into its system planning process within its 2017 Rate Case.[1] On June 14th, 2018 the Commission issued an Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Order"). The order adopted proposed NPA strategies and required the Company to submit an implementation plan and subsequent annual report for each identified NPA project.

Central Hudson provides the following annual report on the progress of each of our NPA projects.

Non-Pipeline Alternative Projects

The Company is pursuing two categories of NPA projects, both of which employ non-traditional solutions to avoid traditional infrastructure construction. The two categories are as follows:

1) *Load Growth-Based Projects*

These types of projects would be designed to manage locational constraints that are associated with peak demand.

2) *Transportation Mode Alternatives*

Central Hudson's transportation mode alternatives projects are designed for strategic abandonment of leak prone pipe through electrification where it is more cost effective than replacement and system reliability is not negatively impacted.

Load Growth-Based Projects

Overview

In an effort to understand location-specific gas distribution costs, Central Hudson employed a consultant, Demand Side Analytics, to perform a system-wide gas distribution avoided costs study. The

[1] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.*

study includes the analysis of approximately 40 localized gas systems throughout Central Hudson's gas service territory. Probabilistic forecasting methods, including simulations of nonlinear growth trajectories, have been used to identify areas of demand growth. This study follows a similar strategy employed for the electric system ("Location Specific T&D Avoided Cost Study Report"[2]), the results of which were included within the Company's DSIP[3]. These results have been combined with an analysis of distribution capacity to identify predicted constraints. Once the study results are finalized, any constrained areas will be evaluated as potential candidates for a load growth-based NPA solution or incorporated into the development of a system-wide value.

Current Status

Central Hudson is currently finalizing the results of the system-wide gas distribution avoided costs study and expects to confirm suitable areas for NPA solutions. Once identified, a technology agnostic market solicitation will occur, following the procedure put in place for Non-Wires Alternatives. Following the solicitation, the Company will file an Implementation Plan in accordance with the Order.

Transportation Mode Alternatives

Overview

Central Hudson's current Transportation Mode Alternatives ("TMA") are designed to facilitate strategic abandonment of leak-prone pipe ("LPP"). LPP is considered to be any natural gas distribution piping that is not made of either plastic or "protected"[4] steel pipe. Common leak-prone materials are wrought iron, cast iron, and unprotected steel. In order to improve safety and reduce ongoing maintenance costs, LPP that cannot be protected or abandoned must be replaced with new plastic pipe. LPP replacement is costly; the Company estimates that it will cost approximately $1.9 million per mile on average in 2019.[5] For a TMA initiative to be successful, each customer's natural gas service would need to be retired.

[2] *Case 15-E-0751 – in the Matter of the Value of Distributed Energy Resources, Central Hudson Gas & Electric Corporation's Avoided T&D Cost Study. July 31, 2018*
[3] *Central Hudson Distribution System Implementation Plan. Revised July 31, 2018*
[4] Pipelines are protected either physically with coatings or with cathodes and sacrificial anodes to prevent corrosion.
[5] Joint Proposal "Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service." Section XVII.E*

Approach

To date, the Company has identified three separate project locations throughout the service territory where it is likely feasible and cost-effective to permanently retire sections of LPP. These three areas, referred to as "cases", were identified in the Company's Implementation Plan & Compliance Filing for Non-Pipe Alternatives ("Implementation Plan").[6] The three locations in Newburgh and Saugerties contain approximately 20 residential customers in total.

The Company is utilizing ICF along with its existing HVAC Trade Ally network to deliver these NPA project solutions. Due to the small number of customers and the need for 100% participation within each area, the Company is utilizing a direct-install approach. Central Hudson is utilizing high efficiency cold climate air-source heat pumps and electric heat pump water heaters to replace the primary natural gas end uses.[7] Other natural gas appliances such as cooking ranges and clothes dryers will be replaced with electric units where applicable. The standard conversion package will be offered at no cost to the customer.[8]

Current Status

The Company initiated its first TMA shortly after filing its Implementation Plan. The case is meeting the expectations of the Company's initial timeline milestones. The initiative utilized a highly targeted marketing approach, followed by customer education and enrollment. The Company has completed its first customer conversion which included converting use of natural gas equipment to efficient electric heating and hot water end uses. Recruitment for the remaining two cases will begin early next year, targeting case completions by the end of 2020.

Benefit Cost Analysis

Central Hudson primarily evaluated the economics of its three ongoing TMA cases based on the Societal Cost Test prescribed within the Company's BCA Handbook.[9] Where applicable, the valuation methodologies from the BCA Handbook, which is primarily intended for electric projects, have been

[6] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives, Filed June 21st 2019
[7] Customers will be educated and have the option to install a geothermal system by covering the incremental cost above the incentive provided for air-source heat pumps
[8] There may be cases where customers desire an "upgraded" appliance, the incremental cost of which would be borne by the customer.
[9] Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 2.0, Revised July 31st, 2018.

used. Some natural gas specific benefits and costs have been included in a way that is similar to those within the BCA Handbook. Relevant benefits and costs have been included in a detailed BCA analysis, developed with support of third party consultants.

The Company estimates these NPA cases to have a Benefit Cost Ratios (BCR)[10] greater than 1.0 based on the three tests included in the BCA Handbook, as reported in more detail within the Implementation Plan. The BCA results within the table below have been revised based on the most current assumptions. Although most BCA results have changed only slightly, the UCT result for Case 3 has changed moderately due to a correction that does not fundamentally affect the viability of the project.

Transportation Mode Alternative – Benefit Cost Ratio by Location			
Case	SCT	UCT	RIM
1	1.41	1.07	2.74
2	6.99	2.14	2.53
3	3.18	1.60	2.28
Weighted Average	3.34	1.64	2.21

[10] Benefit cost ratio, primarily determined by the societal cost test.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Cases 17-E-0459, 17-G-0460 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric & Gas Service

Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives

June 21, 2019

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Contents

1. Background/Description of Need

A Non-Pipes Alternative ("NPA") is a project designed to displace the need for a traditional gas infrastructure investment. Central Hudson originally proposed to incorporate NPA projects into its distributed system planning process within its Rate Case[1]. The proposed strategies were granted approval in the most recent Rate Plan Order[2]. This implementation plan describes the key design parameters and planned execution of three NPA projects, including requirements established within the Rate Plan Order. It also serves as the compliance filing required to establish the NPA incentive associated with the projects.

Central Hudson envisions the potential for multiple types of NPA projects that address various gas infrastructure needs. This implementation plan specifically addresses the displacement of costly replacements of leak-prone pipe. Leak-prone pipe ("LPP") is considered to be any natural gas distribution piping that is not made of either plastic or "protected"[3] steel pipe. Common leak-prone materials are wrought iron, cast iron, and unprotected steel. In most cases, these sections of pipe are essential components of the gas system and must be replaced with new plastic or protected steel pipe. The Company is currently replacing approximately 15 miles of LPP per year in order to improve safety and reduce ongoing maintenance costs. LPP replacement is costly; the Company estimates that it will cost approximately $1.9 million per mile on average in 2019.[4]

The Company has identified three separate project locations throughout the service territory where it is likely feasible and cost-effective to permanently retire non-essential sections of LPP This type of NPA project, referred to as "Transportation Mode Alternative," is requires the conversion existing natural gas users to alternate forms of energy sources, such as electric, so that the LPP asset is no longer in use.

[1] *Order: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9E4F3908-1FBC-4F49-AB00-FDFE18D5586F}*
Attachments: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={13CED81C-066E-48ED-A795-9D7300C4587F}
[2] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*
[3] Pipelines are protected either physically with coatings or with cathodes and sacrificial anodes to prevent corrosion.
[4] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service, p. 22*

For this initiative to be successful, an alternate heating fuel would need to be utilized by all customers that are currently being served with natural gas within the identified sections of LPP (i.e. 100% participation). There are 22 residential customers being served by the targeted infrastructure, making up 3 separate projects, also referred to as cases, in the Newburgh and Saugerties areas.

2. Compliance Requirements

New procedures for NPA tracking, reporting, and cost recovery of such projects have been set forth within the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Rate Order").[5] The Company has been ordered to submit a detailed implementation plan for each NPA, to include the following:

- Detailed measurement and verification procedures;
- Solutions
- The anticipated costs of the NPA
- A demonstration of whether the costs of the NPA projects are incremental to the Company's revenue requirement or will be displacing a project subject to the Net Plant Reconciliation Mechanism
- A customer and community outreach plan
- The BCA results when available.

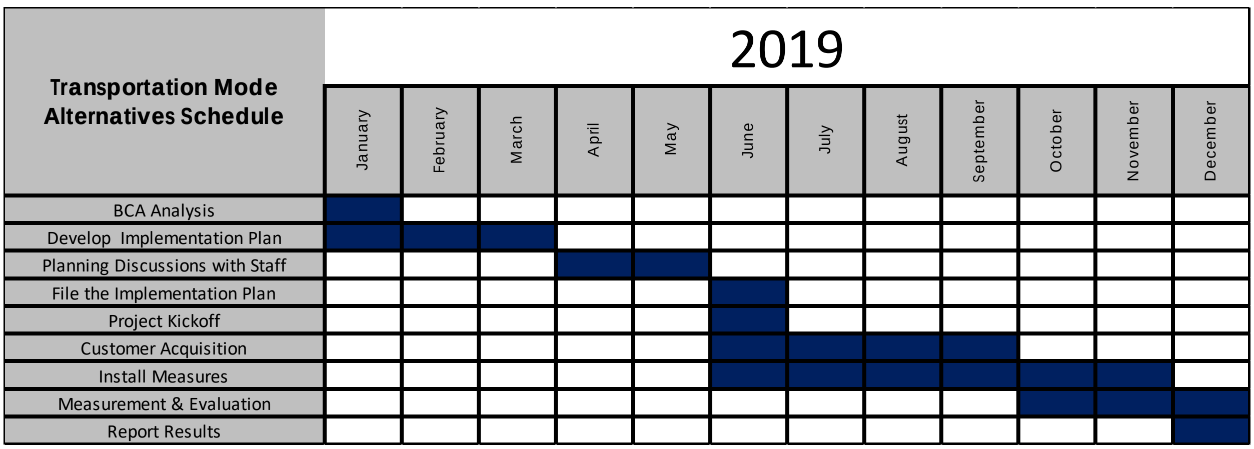
The Rate Order also institutes the mechanism by which the Company may earn incentives associated with NPA projects, and sets forth a requirement for the Company to make a compliance filing to establish that incentive for each project.

Central Hudson held a stakeholder technical conference on Wednesday September 19th, 2018 in our Lake Katrine office. There were 45 stakeholders who either physically or virtually attended. Topics that were presented and discussed include NPA projects, the Natural Gas Avoided Distribution Cost of Service study, a system wide demand response program, and NPA incentive mechanism.

[5] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*

3. Project Timeline

The Company plans to begin deployment of these projects soon after the filing of this implementation plan. An annual NPA Implementation Plan update will be filed in December 2019, which will further the solutions that were deployed. Central Hudson is prepared for a project kickoff in June 2019.



4. Solution

The Company utilized a third party evaluation consultant to determine viable technologies that could cost-effectively eliminate the usage of natural gas in the identified homes. A quantitative and qualitative analysis of these solutions was performed to arrive at the best alternative. Based on the results of the analysis, the Company plans to utilize high efficiency cold climate air-source heat pumps and electric heat pump water heaters to replace the primary natural gas end uses. Other appliances such as ranges may be replaced where applicable.[6]

In 2018, Central Hudson conducted a request for proposals to implement multiple energy efficiency programs. After a rigorous analysis of proposals, ICF was selected to implement these programs. ICF has several years of experience implementing energy efficiency programs for Central Hudson and is currently contracted to implement the residential HVAC energy

[6] Customers will be educated and have the option to install a geothermal system by covering the incremental cost above the incentive provided for air-source heat pumps.

efficiency programs through 2021. The Company will utilize ICF along with its existing Trade Ally network to deliver these NPA project solutions. Due to the small number of customers and the need for 100% participation within each area, the Company plans to utilize a direct install approach, where the project team develops a comprehensive conversion proposal for each customer and performs the installation. The standard conversion package will be offered at no cost to the customer.[7]

5. Measurement & Verification

Measurement & Verification (M&V) will consist of confirmation that all gas services have been retired and the main has been removed from service. The Company will retire the gas infrastructure in accordance with the Gas Operating and Maintenance Procedures. Any updates to the M&V protocol will be included within Central Hudson's December 1, Annual NPA Implementation Plan. More details are provided within Appendix 1.

6. Outreach & Education

Outreach & education efforts will be targeted at the identified 22 residential customers only. To educate the customers about this initiative, educational efforts may include direct mailers, in person meetings, and phone and/or email outreach. ICF will be primarily responsible for education, sales, installation, and logistical efforts, with Central Hudson support where necessary.

7. Benefit Cost Analysis (BCA)

Central Hudson primarily evaluated the economics of this project based on the Societal Cost Test prescribed within the Company's BCA Handbook.[8] All relevant benefits and costs have been included in a detailed BCA analysis, developed with support of third party consultants. The Company estimates this NPA to have a Benefit Cost Ratio (BCR)[9] greater than 1.0 based on the three tests included in the BCA Handbook, indicating that it is beneficial to move forward with the project.

[7] There may be cases where customers desire an "upgraded" appliance, the incremental cost of which would be borne by the customer.
[8] Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 2.0, Revised July 31st, 2018.
[9] Benefit cost ratio, primarily determined by the societal cost test.

Test	BCR
SCT	3.37
UCT	2.15
RIM	2.34

8. Incentive Structure

Per the Rate Order, "The Company will establish an initial incentive equal to 30% of the present value of net benefits", detailed costs and benefits, BCA analysis, and incentive calculation for each of the three projects are included in Confidential Appendix 3. This implementation plan serves as the compliance filing to establish the initial incentive associated with each of the transportation mode alternatives NPAs. Unlike Central Hudson's Non-Wire Alternative ("NWA") program where the shareholder incentive is activated upon procuring 70% of the project targets, the NPA incentive would be earned once full participation in an individual case is reached. Program costs and incentives are amortized over a ten year period and will commence upon the conclusion of the project. More details on the incentive calculation are provided within Appendix 1.

9. Reporting

In December 2019, the Company will file an updated Annual NPA Implementation Plan including:

- NPA expenditures and all relevant details with respect to project costs for each project
- A description of the NPA activities for each project
- NPA cost and incentive recoveries for each project
- Operational savings or other benefits for each project

10. Recovery of Project Expenditures

The costs incurred by the Company for development and implementation of this NPA, including the overall pre-tax rate of return on such costs, will be recovered in accordance with the detailed accounting procedure in Appendix 2 of this filing.

11. Impact to Net Plant

The avoidance of planned leak prone pipe replacement projects will not impact the Company's Net Plant target within the term of the current rate agreement. This Non-Pipe Alternative is expected to be incremental to the Rate Order target of replacing approximately 15 miles of LPP per year through the capital program. If the Company does not meet this target, a true up of the net plant target will only be evaluated if the Company does not replace 15 miles of LPP through the capital program.

Appendix 1- Operating Procedure

Operating Procedure for Transportation Mode Alternative ("TMA") type Non-Pipes Alternative ("NPA") Projects and Incentive Calculations:

Version 1.0

1. Non-Essential Gas Asset Retirement

Central Hudson's TMA projects are designed to strategically retire high-cost natural gas infrastructure[1] by seeking high efficiency electric alternatives to replace natural gas end uses in customer's homes. For each identified area, performance will be measured based on the retirement of all prescribed gas services and mains. The conversion approach will vary by customer based on existing baseline condition, but will primarily focus on high efficiency cold climate air-source heat pumps and electric heat pump water heaters. Other appliance types will be considered based on the existing natural gas end uses for each home.

2. Measurement & Verification

Measurement & Verification (M&V) will consist of confirmation that all gas services have been retired and the main has been removed from service. The Company will retire the gas infrastructure in accordance with the Gas Operating and Maintenance Procedures.[2] Any updates to the M&V protocol will be included within Central Hudson's December 1, Annual NPA Implementation Plan.

3. Reporting

Central Hudson will file an updated implementation plan annually by December 1st. The filing will include:

- Expenditures for each project
- Description of each project's activities
- Each project's cost and incentive
- Operational savings and benefits for each project

[1] The primary target of TMA projects is leak prone pipe that is currently planned for replacement.
[2] Central Hudson's Operations & Maintenance Procedures contains trade secrets, confidential commercial information, and critical infrastructure information, and is therefore protected material. Specifically, the protected material consists of confidential gas O&M procedure(s) for maintaining safe and reliable service to customers. If it is necessary for a specific referenced procedure to be reviewed, Central Hudson will file the appropriate paperwork with the Records Access Officer in accordance with Matter 17-02562, Request for Confidential Treatment.

4. Incentive Calculation

Per the Rate Plan Order[3] Central Hudson's incentives will be determined as a share of the individual project net NPA program benefits. Central Hudson's incentive for deferring capital expenditures will equal 30% of the NPA initial net benefits. The transportation mode alternatives within the NPA portfolio are comprised of distinct targeted areas that are completed on an individual basis. Incentives will be calculated individually for each area once full participation is achieved within that area. Full participation is defined as transitioning all identified customers in each area off of the natural gas distribution network.

Individual project net NPA program benefits and initial project incentives are calculated as follows:

***NPA Project Benefits$_{net}$* =**

$\text{Benefits}_{\text{Avoided Gas Infrastructure Costs}}$

$+\ \text{Benefits}_{\text{Avoided LBMP}}$

$+\ \text{Benefits}_{\text{Avoided Generation Capacity Costs}}$

$+\ \text{Benefits}_{\text{Avoided Electric T\&D Costs}}$

$+\ \text{Benefits}_{\text{Net Avoided CO2}}$

$+\ \text{Benefits}_{\text{Avoided Natural Gas Supply Costs}}$

$+\ \text{Benefits}_{\text{Avoided Ancillary Retail Fuel Costs}}$

$-\ \text{Costs}_{\text{Program Administration}}$

NPA Project Incentives = NPA Project Benefits$_{net}$ x 30%

[3] *Order: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9E4F3908-1FBC-4F49-AB00-FDFE18D5586F}*
Attachments: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={13CED81C-066E-48ED-A795-9D7300C4587F}

$\text{Benefits}_{\text{Avoided Gas Infrastructure Costs}}$ have been provided to Staff by Central Hudson in Appendix 3 of the implementation plan. These values will be fixed for the purposes of this analysis throughout the NPA program period. This includes all future infrastructure replacement, operation, and maintenance costs that are avoided by decommissioning existing natural gas distribution lines and are calculated for each location. These benefits will be fixed assumptions; not to be updated when computing the final incentive amounts.

$\text{Benefits}_{\text{Avoided LBMP}}$ are costs that reflect changes in electricity supply valued at the Locational Based Marginal Price (LBMP) for the Hudson Valley region consistent with the BCA Handbook guidance. This benefit is negative due to the increased electricity consumption associated with fuel switching to electricity. These benefits will be fixed assumptions; not to be updated when computing the final incentive amounts.

$\text{Benefits}_{\text{Avoided Generation Capacity Costs}}$ (AGCC) are costs that reflect changes in coincident system peak demand due to electrification. AGCC costs are calculated by NYISO zone consistent with the BCA Handbook guidance. This benefit is negative due to the increased demand associated with fuel switching to electricity. These benefits will be fixed assumptions; not to be updated when computing the final incentive amounts.

$\text{Benefits}_{\text{Avoided Electric T\&D Costs}}$ are costs that reflect changes to the location-specific load valued at the marginal cost of transmission and distribution (T&D) infrastructure equipment, consistent with BCA Handbook guidance. In some cases, this benefit could be negative due to the increased demand associated with fuel switching to electricity. These benefits will be fixed assumptions; not to be updated when computing the final incentive amounts.

$\text{Benefits}_{\text{Net Avoided CO2 Costs}}$ *a*ccount for carbon dioxide emissions impacts due to changes in system load levels. These benefits are valued using the Social Cost of Carbon (SCC), net of the expected Regional Greenhouse Gas Initiative (RGGI) allowance values, as provided by Department of Public Service Staff.[4] These benefits will be fixed assumptions; not to be updated when computing the final incentive amounts.

$\text{Benefits}_{\text{Avoided Natural Gas Supply Costs}}$ include the wholesale natural gas supply costs that are avoided as a result of electrification, valued as the CARIS 2018 forecasted natural gas prices. These benefits are calculated at the end use level for each project participant. These benefits will not be updated when computing the incentive impacts.

[4] Case 15-E-0751 – Value of Distributed Energy Resources, Updated Environmental Value

$\text{Benefits}_{\text{Avoided Ancillary Retail Fuel Costs}}$ include the retail fuel oil and propane fuel costs that are avoided as a result of electrification, valued as the 2017-2018 NYSERDA Hudson regional averages for each respective fuel type. These benefits are calculated at the end use level for each project participant. These benefits will be fixed assumptions; not to be updated when computing the final incentive amounts.

$\text{Costs}_{\text{Administration}}$ include all fees paid to program providers and customers, including fixed program support fees, incentives for purchasing new electric based equipment. Actual costs of each project will be utilized to calculate the final incentive amount at the time the projects is deemed completed.[5] Additionally, $\text{Costs}_{\text{Administration}}$ include costs internal to Central Hudson to manage the program, as well as third party program evaluation and consulting support that is procured as needed. All program costs will be trued-up to actual expenditures at the conclusion of each project for the purposes of incentive calculation. In some cases, customers may choose to pay the incremental cost for an upgraded appliance or HVAC system that is more costly than the standard conversion offer. Incremental participant costs will not be included in the BCA analysis.

Many assumptions used in calculating the BCA of the individual projects will be consistent with the BCA Handbook Version 2.0 filed on July 31, 2018. The BCA Handbook is designed specifically for electrical projects, but many aspects of the BCA framework apply to natural gas. Other assumptions utilized in the development of the BCA, including the WACC, have been utilized in a manner consistent with the BCA Handbook.[6] These assumptions will not be updated throughout the term of these NPA projects for the purposes of calculating the utility incentives.

Central Hudson will record and amortize the incentive payout as detailed in the accounting procedure which has been filed confidentially in Appendix 2 of the Implementation Plan. The incentive and expense recovery mechanism will commence once Central Hudson has deemed all projects completed. This will be collected in the Gas Miscellaneous Charge on Central Hudson customer gas bills. The incentive will be calculated on a case by case basis and will contingent upon full participation in each area. This differs from the Non-Wire's Alternative ("NWA") projects where incentives commence at the 70% attainment level.

[5] A portion of these costs are currently set within the Master Services Agreement between Central Hudson and its implementation vendor.
[6] Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 2.0, Revised July 31st, 2018.

Appendix 2- NPA Accounting Procedure

Non-Pipe Alternative – #A30.63
Deferral and amortization of NPA

As prescribed in the 2018 Rate Order, Central Hudson is authorized to defer the revenue requirement effect of development and implementation of Non-Pipe Alternative ("NPA") projects. Specifically, Central Hudson will maintain appropriate accounting to adjust net plant targets by removing the effect of the capital project not implemented. *To the extent the Company implements a NPA that results in the <u>displacement of a capital</u> project reflected in <u>the average gas net utility plant, the balance(s) will be reduced to exclude the forecast net plant associated with the displaced project. The carrying charge, or a portion thereof, as warranted, on the reduction of the average gas net utility plant that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NPA.</u>*

WO#7341A Transp. Mode Alt. (Abandonment) has been set up within PSC account 182.44 to track expenditures related to this initiative. Financial Reporting will monitor charges on a monthly basis and record associated deferred taxes. Once the program is completed, program cost and incentive will be recovered via the Gas Miscellaneous Charge over a ten year period. Carrying charges at the Pretax WACC will be assessed on deferred balances. In accordance with 2018 Rate Order, each December total accumulated CC are moved via non-standard offset JV to the Regulatory Adjustment Mechanism ("RAM") work order for collection/refund to customer from July – June in each subsequent rate year).

To record deferred taxes related to NPA (JV 399)

Dr. 41550-2-930 (410.12)	Def FIT – Non Pipe Alternative
Cr. 28359-3-970	Def FIT – Non Pipe Alternative (182.44)
Dr. 41552-2-930 (410.16)	Def SIT – Non Pipe Alternative
Cr. 28459-3-970	Def SIT – Non-Pipe Alternative (182.44)
Dr. 28340-3-970	Def FIT – SIT Contra
Cr. 41186-2-930 (410.12)	Def FIT – SIT Contra

*To record carrying charges on the NPA (***JV388)**

Dr. W.O. #6469A (182.39)	CC – Transp Mode Alt (Aband)
Cr. 42152-3-970 (421.52)	CC – NPA
Dr. 41044-3-970 (410.44)	Def FIT – CC – NPA
Cr. 28301-3-970	Def FIT – CC – NPA
Dr. 41045-3-970 (410.45)	Def SIT – CC – NPA
Cr. 28401-3-970	Def SIT – CC – NPA
Dr. 28352-3-970	Def FIT – SIT Contra
Cr. 41134-3-970 (411.34)	Def FIT – SIT Contra

Prepared by: M. Petrollese
Reviewed by: A. Banks

Appendix 3- Benefit Cost Analysis

REDACTED

December 1, 2020

Hon. Michelle L. Phillips
Secretary
New York State Public Service Commission
Agency Building 3
Albany, NY 12223-1350

Re: Case 17-G-0460 – *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*; Non-Pipeline Alternatives Compliance Filing

Dear Secretary Phillips:

In compliance with the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan issued on June 14, 2018 in the above-referenced case, Central Hudson Gas & Electric Corporation hereby submits its 2020 Non-Pipeline Alternatives Annual Report.

Questions regarding this filing may be directed to Mark Sclafani at (845)486-5979 or msclafani@cenhud.com.

Respectfully submitted,

/s/*Paul A. Colbert*

Paul A. Colbert
Associate General Counsel
Regulatory Affairs

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	**Case 17-G-0460**

Central Hudson Gas & Electric Corporation's Non-Pipeline Alternatives Annual Report

December 1, 2020

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

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Background

Non-Pipeline Alternatives ("NPAs") are projects designed to displace the need for traditional gas infrastructure investment. Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") proposed to incorporate NPA projects into its system planning process within its 2017 Rate Case. [1] On June 14th, 2018 the Commission issued an Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Order"). The Order adopted proposed NPA strategies and required the Company to submit an implementation plan and subsequent annual report for each identified NPA project. Central Hudson provides this annual report on the progress of each of its NPA projects.

Non-Pipeline Alternative Projects

The Company is pursuing two categories of NPA projects, both of which employ non-traditional solutions to avoid traditional infrastructure construction.

1) *Transportation Mode Alternatives*

Central Hudson's transportation mode alternatives projects are designed for strategic abandonment of leak prone pipe through electrification where it is more cost effective than replacement and system reliability is not negatively impacted.

2) *Load Growth-Based Projects*

These types of projects would be designed to manage locational constraints that are associated with peak demand.

[1] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.*

Transportation Mode Alternatives

Overview

Central Hudson's current Transportation Mode Alternatives ("TMA") are designed to facilitate strategic abandonment of leak-prone pipe ("LPP"). LPP is considered to be any natural gas distribution piping that is not made of either plastic or "protected"[2] steel pipe. Common leak-prone materials are wrought iron, cast iron, and unprotected steel. In order to improve safety and reduce ongoing maintenance costs, LPP that cannot be protected or abandoned must be replaced with new plastic pipe. LPP replacement is costly; in 2019, the Company estimated its cost to be approximately $1.9 million per mile on average.[3]

Approach

Through electrification of customers' heating and appliances, LPP can be retired permanently in strategic locations. The approach is ideal for low customer saturation areas with high LPP replacement costs. For a TMA initiative to be successful, all of the natural gas customers served by the designated infrastructure must agree to retire their gas service.

To date, the Company has identified 39 separate TMA project locations throughout its service territory where it is potentially feasible and cost-effective to permanently retire sections of LPP.
These 39 project locations, referred to as "cases", include approximately 100 customers in total.

The first three cases were submitted in "Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives"[4] ("2019 Implementation Plan"), filed in June 2019.

In 2020, the Company broadened its scope for potential projects and identified 36 additional cases as potential TMA candidates. Five cases were identified as "high priority" and included in "Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe

[2] Pipelines are protected either physically with coatings or with cathodes and sacrificial anodes to prevent corrosion.
[3] Joint Proposal "Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service." Section XVII.E*
[4] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives, Filed June, 21 2019

Alternatives: Transportation Mode Alternatives"[5] (2020 Implementation Plan"), filed June, 12 2020. Cases have been designated as high priority when they have heighted time constraints due to concurrent Company or municipal initiatives. Central Hudson pursues TMA cases based on a determined priority, as opposed to their chronological identification. Implementation Plan updates will be forthcoming as cases are determined to move forward.

The Company has partnered with ICF along with its existing HVAC Trade Ally network to deliver these NPA project solutions. Due to the small number of customers and the need for 100% participation within each area, a direct install approach is utilized. The initiative employs a highly targeted marketing strategy, followed by customer education and enrollment. High efficiency cold climate air-source heat pumps and electric heat pump water heaters are utilized to replace the primary natural gas end uses. Air source heat pump installations are performed in compliance with NYS Clean Heat[6] guidelines. Other natural gas appliances such as cooking ranges and clothes dryers are replaced with electric units where applicable. Customers are provided a standard conversion package at no cost[7] and may also receive a financial bonus incentive upon project completion.

Current Status

The Initial Three TMA Cases (2019)

In 2019, The Company initiated its first TMA case shortly after filing its 2019 Implementation Plan.

Case 1: The first case consists of two customers. One customer went forward with the conversion in December 2019 which included converting existing natural gas equipment to efficient electric heating and hot water end uses, appliance replacements, and a financial completion bonus. The second property lies on a corner lot and is expected to receive a service line relocation as part of a pipeline replacement occurring on the adjacent street beside the property.

Case 2: This case also consists of two customers. This case has been eliminated as a potential TMA candidate. After further review, the Company learned that one property had previously retired its gas

[5] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Transportation Mode Alternatives, filed June, 12 2020
[6] See https://www.nyserda.ny.gov/All-Programs/Programs/NYS-Clean-Heat.
[7] There may be cases where customers desire an "upgraded" appliance, the incremental cost of which would be borne by the customer.[8] Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 2.0, revised July 31st, 2018.

use. The second property is able to access gas from another nearby gas main. The LPP main targeted as part of the TMA project is still planned for retirement.

Case 3: This case includes approximately 18 customers. This case will be revisited after recruitment efforts are refined through smaller cases and those under tighter timeline constraints.

Table 1: Project Summary - Initial Three TMA Cases (2019)

Transportation Mode Alternative detail by Case Location:			
Proposed	**Case**	**Participants**	**Status**
June 2019	1	**2**	Successful TMA conversion. Service line relocation for one property
	2	**2**	Removed from scope
	3	**18**	Future project

High Priority Cases (2020)

Five "high priority" cases were included in Central Hudson's 2020 Implementation Plan. These cases were prioritized to coordinate with local municipal projects such as street repaving.

Case 4: This case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Case 5: This case involving three properties has successfully moved forward with a TMA strategy. One property received a full TMA conversion which included converting existing natural gas equipment to efficient electric heating and hot water end uses, an appliance replacement, and financial completion bonus. The remaining two properties will receive new gas service lines since they are within 100 feet of a new main on an adjacent street and could request gas service in the future. With the completion of this case, Central Hudson plans to file for its first TMA incentive in the first half of 2021.

Case 6: This cases consists of a single structure that is overseen by a Board of Directors. The Board supports the conversion in concept, however, plans to expand their footprint and does not want to forego access to natural gas. The customer plans to install a gas-fired backup generator. The municipal project initially driving the priority of this case has been delayed until 2021, allowing more time to finalize this case. For the time being, discussions remain open as the Board continues its planning.

Case 7: This case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Case 8: This case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Table 2: Project Summary - High Priority Cases (2020)

Transportation Mode Alternative detail by Case Location:			
Proposed	**Case**	**Participants**	**Status**
June 2020	4	**2**	Lacked 100% commitment
	5	**3**	Successful TMA conversion. Service line relocation for additional properties
	6	**1**	Discussions remain open
	7	**2**	Lacked 100% commitment
	8	**2**	Lacked 100% commitment

Unplanned High Priority Cases (2020)

As part of a broadened strategy in 2020, Central Hudson attempted to apply the TMA strategy to two Unplanned High Priority cases. These opportunities were identified “in the field” when unique challenges arose during traditional pipeline installation efforts. Each case involved a single dwelling. Central Hudson engaged with each property owner and offered a full TMA conversion at no cost, coupled with sizable monetary incentives. Neither case was able to achieve customer commitment. One offer was declined, noting a preference for natural gas heat and future consideration of a gas-fired backup generator. The offer for the second location exchanged initial communications, but failed to achieve response in subsequent efforts. The Company would have filed an Implementation Plan update should there have been a path to move forward.

Benefit Cost Analysis

Central Hudson primarily evaluated the economics of its TMA cases based on the Societal Cost Test prescribed within the Company’s BCA Handbook.[8] Where applicable, the valuation methodologies from the BCA Handbook, which are primarily intended for electric projects, have been used. Some natural gas specific benefits and costs have been included in a way that is similar to those within the BCA

[8] Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 2.0, revised July 31st, 2018.

Handbook. Relevant benefits and costs have been included in a detailed BCA analysis, developed with support of third party consultants.

The Company estimates these NPA cases to have a Benefit Cost Ratios (BCR)[9] greater than 1.0 based on the three tests included in the BCA Handbook, as reported in more detail within the Implementation Plan. The BCA results within the table below have been revised based on the most current assumptions.

Table 3: All Cases - BCAs and Project Status Summary

Transportation Mode Alternative – Benefit Cost Ratio by Case Location:					
Proposed	**Case**	**SCT**	**UCT**	**RIM**	**Status**
June 2019	1	**1.14**	**0.93**	**2.71**	Successful TMA conversion. Service line relocation for one property
	2	**6.54**	**2.1**	**2.51**	Removed from Scope
	3	**2.87**	**1.52**	**2.23**	Future project
June 2020	4	**1.94**	**1.3**	**1.37**	Lacked 100% commitment
	5	**5.18**	**1.97**	**2.15**	Successful TMA conversion. Service line relocation for additional properties
	6	**4.66**	**1.9**	**2.13**	Discussions remain open
	7	**1.13**	**0.9**	**1.22**	Lacked 100% commitment
	8	**2.04**	**1.31**	**1.69**	Lacked 100% commitment

This year, Central Hudson partnered with a third party evaluator, Applied Energy Group, to create a proprietary BCA screening tool to use in preliminary case evaluations. This tool provides valuable time savings and an increased ability to adjust for alternative scenario assumptions in initial BCA screenings. Central Hudson is continually refining its benefit cost analysis protocols to most accurately account for all related costs and benefits. Any material changes are done in consultation with DPS Staff.

Load Growth-Based Projects

Overview

In an effort to understand location-specific gas distribution costs, Central Hudson employed a consultant, Demand Side Analytics, to perform the "2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods"[10] ("Avoided Gas Distribution Study"). The study includes the analysis of approximately 40 localized gas systems throughout Central

[9] The benefit cost ratio is primarily determined by the societal cost test.
[10] Cases 17-E-0459, 17-G-0460, 18-M-0084 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service; In the Matter of a Comprehensive Energy Efficiency Initiative, 2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods. (filed June, 18 2020) Using Probabilistic Forecasting and Planning Methods

Hudson's gas service territory. Probabilistic forecasting methods, including simulations of nonlinear growth trajectories, have been used to identify areas of demand growth. The study is based on a methodology consistent with the "Location Specific T&D Avoided Cost Study Report"[11] conducted for Central Hudson's electric system planning and included within the Company's 2020 DSIP[12] filing.

The avoided gas distribution study concluded that there are no imminent constraints on the gas distribution system that would warrant the development of a Non-Pipeline Alternative at this time. All potential avoidable distribution cost or deferral value is concentrated in a single gas distribution system, referred to as the PN Line, which serves customers in the southern portion of the Town of Poughkeepsie. The PN Line is highly loaded but is experiencing near flat annual growth (-0.10%), with some uncertainty. There is a risk of exceeding the system's design parameters within the next four years, but the likelihood is less than 10%, with "the most likely outcome for loads to remain below pressure constraints over the next decade."[13] Relatively small amounts of demand management or local supply resources can further reduce this risk for the foreseeable future.

Current Status

Within the Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025[14], ("Energy Efficiency Order") the Commission encouraged utilities to utilize targeted energy efficiency to support constraints on the gas distribution system. As stated by the Commission, "…the kicker concept can apply equally to gas efficiency programs, where supply constraints create a value for gas peak reduction. Each utility should consider the potential for gas kickers to provide system value."

While the potential for future investment in the PN line is not certain enough to warrant the development of a non-pipeline alternative at this time, Central Hudson has considered this an opportunity to leverage existing initiatives to manage the potential for a future load constraint. With a focus on the PN Line, Central Hudson evaluated its existing portfolio of energy efficiency and electrification technologies in conjunction with "kickers" in a peak load management application. Kickers provide a flexible, low cost solution that can be implemented on an as-needed basis. Six energy efficiency and electrification measures currently offered within Central Hudson's Demand Side Management program were considered. These measures are all currently deployed within Central Hudson's programs and have been determined to be broadly cost effective. To assess the use of kickers,

[11] Case 15-E-0751 – in the Matter of the Value of Distributed Energy Resources, Central Hudson Gas & Electric Corporation's Avoided T&D Cost Study. June 30, 2020
[12] Central Hudson Distribution System Implementation Plan, June 30, 2020.
[13] 2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods, p.34.
[14] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025. Issued and Effective January 16, 2020

Central Hudson conducted a simplified analysis to compare the incremental costs of higher incentives and benefits associated with more concentrated load reductions. The analysis, referred to as the Locational Benefit-Cost Analysis indicates that the smart thermostats[15] are the most cost effective measure to deliver targeted load reductions.

Implementation

Central Hudson is currently implementing a "kicker" incentive to promote ENERGY STAR certified smart thermostats to customers served by the Vassar Road portion of the PN Line with the goal of providing more concentrated load relief to that system.

In November of 2020, the Company initiated its "Double the Rebates" marketing campaign to approximately 750 residential and commercial customers in the targeted area. Customers have the opportunity to choose from a broad selection of eligible smart thermostats available at a variety of retailers. Customers can receive Central Hudson's standard smart thermostat rebate plus an additional rebate of equal value. Combined, the rebates equal $100 per thermostat. Each eligible household may purchase up to two smart thermostats.

This initiative is supported by energy efficiency budgets. Per the Energy Efficiency Order, "utilities employing kickers have the flexibility to adjust the portion of the budget spent on kickers as appropriate based on further experience." Central Hudson plans to implement this initiative on an as-needed basis and set incentive levels based in consideration of existing portfolio budgets.

A progress update on this initiative will be provided in the Company's next annual report.

[15] A smart (learning) thermostat controls HVAC equipment to regulate the temperature of the room or space in which it is installed, communicates with sources external to the HVAC system for remote adjustment and has the ability to reduce overall gas consumption by performing automatic adjustments in response to occupant behavior.

ENBRIDGE GAS INC.

Undertaking Response to GEC

To advise the carbon cost included in ICF's application of the 2016 conservation potential to its study.

Response:

As noted on page 10 of the 2016 OEB Conservation Potential Study ("CPS"):[1]

> "The economic screen that was used in the economic potential scenario was the TRC-plus cost effectiveness test"

and

> "The TRC-plus test includes a 15% adder that accounts for the non-energy benefits associated with DSM programs, such as environmental, economic and social benefits".

Further, at page 11 of the 2016 CPS, ICF notes that:

> "Achievable Potential is defined as the portion of the economic conservation potential that takes into account realistic market penetration rates of cost-effective measures over the study period."

However, as noted on p. 7,

> "Measure TRC-plus results do not include program costs such as program administrative (non-incentive) costs and adjustments for free ridership, spillover effects, and persistence".

As such, some of the measures that are included in the achievable potential savings would not meet the TRC-plus cost-effectiveness screen if they were considered on a stand-alone basis as part of a DSM program offering.

Furthermore, Section 7.2 of the 2016 CPS summarizes the results of a sensitivity analysis that was completed as part of this study. A sensitivity analysis scenario that

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[1] ICF Natural Gas Conservation Potential Study: Final Report, July 7, 2016; https://secure-web.cisco.com/1n-DLpH-5mKa3qm6T_EGD_pbD3EL2km-PCQM6ABBCg2eV3NLCkIZbka_TwcVMNkkK12eSgrjIaDWddKIY0OY-Pera2vgATQ4VFAKLpQTUM5DP34Eu45y9Ua2yoG7vAychfKyj40jkgl9w_8FE7PIM9YHt4tlj0vQTMzPi0TeOtF9aRNxsr2_9a8B4a6zI28Vxn-dUccQf59w4wGxitRVRBNk7ZyMxTuc1Ro_lXRH3svboahcQDC53Q3-T8BfNheBY-WyE0x55erFxQuxnJYus1y-zAVelLjlizrJVfO1R045xM--4YG40A1MwbtT1V1XY/https%3A%2F%2Fwww.oeb.ca%2Fsites%2Fdefault%2Ffiles%2Fuploads%2FICF_Report_Gas_Conservation_Potential_Study.pdf

investigated the impacts of increasing the avoided costs by 50% in order to account for the possibility of higher commodity prices, natural gas price suppression effects, and a price on carbon in the future estimated that the unconstrained achievable potential would increase by 15% by 2030.

ENBRIDGE GAS INC.

Undertaking Response to GEC

To itemize the areas where Ontario might be seen as lagging in comparison with New York state with respect to DER's, energy efficiency, and decarbonization.

Response:

ICF's 2020 Jurisdictional Review Report, which was filed by Enbridge Gas as part of its Additional Evidence at Exhibit B, Appendix A, provides additional details of areas where Ontario is lagging in comparison with that of New York State with regard to:

- **Distributed energy resources (DERs):** A comparison of Ontario and New York in the context of non-wires solutions (NWS) and DERs is provided at pages 55-63.
- **Energy efficiency:** A comparison of Ontario and New York in the context of natural gas energy efficiency is provided at pages 49-54.
- **Decarbonization:** A comparison of Ontario and New York in the context of carbon policy is provided at pages 54-55.

These sections and other parts of ICF's 2020 Jurisdictional Review Report (see pages 4-5) also highlight structural differences between Ontario and New York State that have contributed to the latter's progress with regards to the advancement of DERs, energy efficiency, and decarbonization, such as:

(i) Fundamentally higher energy costs in New York State;
(ii) Higher natural gas and power distribution infrastructure costs (particularly in Downstate New York);
(iii) A lower proportion of industrial demand;
(iv) The presence of joint natural gas and electric utilities; and
(v) Clear, consistent top-down policy direction from the New York State government related to transitioning to a decarbonized economy and prioritizing DSM and other demand-side options.