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June 6, 2022

VIA ELECTRONIC FILING AND FEDEX MAIL

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: Consolidated UG 435 / UG 411 / Application of NW Natural for a General Rate Revision/Schedule 198 Renewable Natural Gas Recovery Mechanism Reply Testimony

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith its Reply Testimony for the above-mentioned consolidated proceedings.

Please note, this filing contains confidential and highly confidential information that represents business-sensitive, non-public information and will be provided subject to General Protective Order No. 21-461 and Modified Protective Order No. 21-465.

Please address correspondence on this matter to me with copies to the following:

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Respectfully submitted,

NW Natural

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Enclosures

CERTIFICATE OF SERVICE
UG 435 / UG 411

I hereby certify that on June 6, 2022, I have served the unredacted, confidential and highly confidential versions of NW NATURAL'S REPLY TESTIMONY upon parties of record in docket UG 435 by electronic or FedEx mail.

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DATED June 6, 2022, Portland, Oregon.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Reply Testimony of Zachary D. Kravitz

LOW INCOME RATES, CUSTOMER DEPOSITS AND RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE
EXHIBIT 1600

June 6, 2021

EXHIBIT 1600 – REPLY TESTIMONY – LOW INCOME RATES, CUSTOMER DEPOSITS AND RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Zachary Kravitz who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company ("NW Natural" or the "Company")?

A. Yes, along with David Anderson, I presented NW Natural/100, Anderson-Kravitz. I also presented NW Natural/1500, Kravitz.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to: (1) provide an overview of the issues that will still be litigated in this case following the settlement of certain issues pursuant to a multi-party stipulation; (2) respond to the Opening Testimony of Public Utility Commission of Oregon Staff ("Staff"), Oregon Citizens' Utility Board ("CUB"), and the Coalition[1] regarding discounted rates for low-income customers; (3) respond to CUB's proposal to eliminate residential customer deposits; and (4) respond to the Opening Testimony of Staff, CUB, and the Alliance of Western Energy Consumers ("AWEC") regarding Schedule 198, Renewable Natural Gas Recovery Mechanism. Schedule 198 is an automatic adjustment clause ("AAC") that is designed to recover NW Natural's qualified investments in renewable natural gas ("RNG") infrastructure.

[1] The "Coalition" is comprised collectively of The Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

Q. Please summarize your testimony.

A. In my Reply Testimony, I first summarize the issues that are still being litigated following the resolution of certain issues pursuant to a multi-party settlement agreement, and explain that because the issues in this proceeding have been narrowed considerably, the Company is not providing Reply Testimony on all topics addressed in the parties' Opening Testimony. Next, I explain how the Company is proposing a new Low-Income Bill Discount Program which will serve as an additional tool to reduce the energy burden of the Company's low-income customers, and which is incremental to the Company's existing low-income rate mitigation offerings. Third, I respond to CUB's proposal to eliminate all residential customer deposits, and explain why it would be appropriate to eliminate residential customer deposits only for self-certifying low-income customers, and continue to collect residential customer deposits from other (non-low-income) customers.

Finally, I address Staff, CUB, and AWEC's Opening Testimony regarding the RNG AAC (Schedule 198). I respond to AWEC's argument that Schedule 198 is not necessary because existing regulatory mechanisms, specifically general rate cases and the Company's ability to request deferrals, are sufficient to ensure that NW Natural can recover the prudently incurred costs of qualified investments in RNG infrastructure. I also respond to CUB's proposed revisions to the Company's Schedule 198. While the Company accepts several of CUB's recommendations, several others are either too restrictive or seek to make Schedule 198 unduly punitive. I also address AWEC's argument that Schedule 198, if ultimately adopted, should not permit deferrals for projects in service prior to being included in rates, and, if they are, should be subject to an earnings test that is equal to 100 basis points less than NW Natural's authorized return on equity ("ROE"). Lastly, I address several concerns that Staff expressed in its Opening Testimony regarding whether Schedule 198 should be used generically for all qualified investments that exceed $5 million or should be limited to only the Lexington RNG project at this time.

II. OVERVIEW OF LITIGATED ISSUES

Q. Has NW Natural engaged in settlement discussions with the parties to this general rate case?

A. Yes, NW Natural and all parties have engaged in settlement discussions. As a result of those settlement discussions, NW Natural, Staff"), the CUB"), AWEC, and the Small Business Utility Advocates ("SBUA") (collectively, the "Stipulating Parties") entered into a multi-party partial stipulation addressing revenue requirement, rate spread, and certain other issues ("Stipulation"), which was filed in this docket on Tuesday, May 31, 2022. As a result of the Stipulation, the issues that will be litigated in this proceeding have been substantially narrowed. The Coalition, however, did not sign on to the Stipulation. Accordingly, NW Natural is not filing Reply Testimony addressing all of the issues raised in the parties' Opening Testimony, and instead is filing Reply Testimony addressing only the issues that are still being litigated.

Q. What issues are not included in the Stipulation and are still being litigated in this proceeding?

A. The following issues are not included in the Stipulation and are still being litigated in this proceeding:

- Proposal to eliminate all Residential Customer Deposits (CUB/100);
- Proposals to modify the Company's Line Extension Allowance (CUB/100; Coalition/100; Coalition/200);
- Proposed modifications to the Oregon Low-Income Energy Efficiency program ("OLIEE") Program (Coalition/300);
- Expenditure restrictions on energy efficiency program funds generated through the public purpose charge on rate payers (Coalition/300);
- Policy concerns regarding energy burdens and costs of rates on low-income ratepayers (Coalition/300);
- Proposal to modify the Company's Decoupling mechanism (Scala/1300);
- Proposals related to the RNG AAC (NWN/1500, Staff/1700, AWEC/100, CUB/200);
- Cost Recovery and Rate Spread of the Lexington RNG Project and Deferral (NWN/1100; CUB/200; Staff/1700; AWEC/100; Coalition/100); and
- COVID-19 Deferral Amortization and Rate Spread (Staff/1500).

Q. What issues are included in the Stipulation and are still being litigated in this proceeding by the Coalition?

A. My understanding is that the following issues are addressed in the Stipulation and are still being litigated by the Coalition:

- Advertising expense (Coalition/400);
- Expense related to the Company's memberships and dues in industry organizations like the American Gas Association and the Northwest Gas Association (Coalition/400); and
- Expense related to the Company's political activity and lobbying (Coalition/400).

III. DISCOUNTED RATES FOR LOW-INCOME CUSTOMERS

Q. Please describe the recent legislative and Commission activity regarding low income rates.

A. In the 2021 Legislative Session, the Oregon Legislature approved House Bill ("HB") 2475, which directed the Commission to include equity and environmental justice considerations in Commission processes, and also amended ORS 757.230 to provide the Commission with the authority to consider differential energy burdens for low-income customers and to approve differential rates for low-income customers. The Commission initiated a proceeding to address the implementation of HB 2475 in docket UM 2211, and NW Natural has been an active participant in that docket.

Q. Did NW Natural propose a Low-Income Bill Discount Program in this proceeding?

A. No. NW Natural filed its proposed interim Low-Income Bill Discount Program on April 18, 2022, docketed by the Commission as docket ADV 1390,[2] and filed an application to defer the administrative costs associated with the program in docket UM 2233, which was approved in Order No. 22-113. Additionally, NW Natural is completing a Low Income Needs Assessment ("LINA"), which will be completed in July 2022. Based on the schedule contemplated by ADV 1390, NW Natural expects that the interim Low-Income Bill Discount Program will be in place on or before November 1, 2022. Additionally, after learning more from the investigation in docket UM 2211 and the LINA, and after receiving additional direction from the Commission, the Company expects to develop a permanent low-income rate program.

Q. Did the parties in this general rate case comment regarding discounted rates for low-income customers?

A. Yes. Staff, CUB, and the Coalition provided testimony addressing discounted rates for low-income customers.

[2] Staff and the Coalition indicated that NW Natural filed the Low-Income Bill Discount Program in docket UM 2211, however the proposal was not formally filed in UM 2211. Instead, NW Natural filed it as a new tariff and it was given the docket ADV 1390, which is the operative docket. Staff has posted information from other dockets (such as, COVID docket UM 2114 and PGE's bill discount, docket ADV 1365) in the HB 2475 docket that is UM 2211.

Q. What is Staff's position regarding discounted rates for low-income customers?

A. Staff observes that the Company is proposing a bill discount program for low-income customers, which is in addition to the other programs that NW Natural offers to promote affordability for its customers.[3] Staff comments that the other programs include NW Natural's Oregon Low Income Gas Assistance Program ("OLGA"), supplemental low-income assistance program, Gas Assistance Program ("GAP"), low income weatherization through the OLIEE, as well as federal funding available through the Low-Income Home Energy Assistance Program ("LIHEAP").[4] Because the Company has formally announced its proposal in docket ADV 1390 and described its implementation schedules and engagement strategies, Staff does not make any further recommendations regarding low income rates in this proceeding and comments that it is supportive of the Company's efforts.[5]

Q. What is CUB's position regarding discounted rates for low-income customers?

A. CUB comments that with the combined effect of the current rate case and the 2021 purchased gas adjustment ("PGA"), customer rates would be 25 percent higher than when the legislature approved HB 2475.[6] CUB asserts that there is an urgent

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[3] Staff/1300, Scala/11.

[4] Staff/1300, Scala/11-12.

[5] Staff/1300, Scala/15.

[6] CUB/100, Jenks/26.

need to implement low income rates before next winter's heating season, and suggests that if nothing is done before then, "the Commission could consider extending NW Natural's 20 [percent] employee discount to customers who self-certify that their income qualifies them for low-income assistance until a permanent program is implemented."[7]

Q. How do you respond to CUB's proposal?

A. NW Natural agrees that there is a pressing need to implement low-income rates, and as explained above, the Company plans to have a discounted rate offering for low-income customers in place by November 1, 2022. NW Natural shares CUB's sense of urgency regarding the need to mitigate the energy burden of low-income customers. The Company believes, however, that the process that is currently underway in docket UM 2211 and ADV 1390 will allow for robust input from the Commission and stakeholders, and will result in an offering that will provide meaningful assistance to meet the needs of the Company's low-income customers—incremental to the Company's existing low-income offerings. Because the Company expects to have a low-income rate offering in place by the time rates go into effect in this case, the Commission should reject CUB's proposal to extend the employee discount to low-income customers.

[7] *Id.* at 26-27.

Q. What is the Coalition's position regarding discounted rates for low-income customers?

A. The Coalition comments that the low-income rate offering is being addressed with the Company's proposed bill discount program and does not propose modifications to the Company's proposal in this proceeding.[8] Additionally, the Coalition indicates that it will provide comments on the Company's proposal in docket ADV 1390.[9] While the Coalition is not making any specific recommendations regarding the low income rate offering in this proceeding, the Coalition nonetheless expresses concern that the bill discount program will not provide adequate relief to low-income customers, and asks that the Commission consider the bill discount proposal in the context of an overall rate increase.[10] Similar to the point that CUB makes, the Coalition asserts that in light of the 2021 PGA increase and the increase proposed in this proceeding, which together would amount to a 25 percent increase, the bill discount program would only allow low-income customers to break even—or pay the rates in effect at the time the legislature approved HB 2475—which would not serve to reduce their energy burden.[11]

Q. How do you respond to the Coalition?

A. NW Natural appreciates the Coalition's engagement in the UM 2211 proceeding, and looks forward to continuing engagement from the Coalition in that proceeding

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8 Coalition/300, Fain/15.

9 Coalition/300, Fain/15. In fact, on May 27, 2022, certain members of the Coalition (Community Energy Project, Climate Solutions, Verde, and Coalition of Communities of Color) did provide comments on the Company's proposed Low-Income Bill Discount Program in ADV 1390.

and in ADV 1390 regarding the Company's interim Low-Income Bill Discount Program. NW Natural shares the Coalition's concern regarding the energy burden of low-income customers; however, the Coalition's assertions regarding the interim Low-Income Bill Discount Program relative to the rate increase in the 2021 PGA, and in this case, does not consider the totality of the Company's low-income rate mitigation offerings. As Staff noted, the Company offers other forms of low-income assistance through OLGA, GAP, and OLIEE, and there is additional federal funding available from LIHEAP. Table 1, below, illustrates the impacts of the Company's proposed interim Low-Income Bill Discount Program using the as-filed proposed rates from Wyman/1404. Table 2 provides the average benefit amounts for the OLGA, GAP and LIHEAP programs for the past three program years. These tables demonstrate that any combination of these programs will provide a means to meaningfully reduce energy burden for low-income customers.

Table 1 – Interim Low Income Bill Discount Program – Annualized Average Bill

	UG 435 Proposed Rates
Average Bill	$847.69
Bill w Tier 1 discount (25%)	$635.77
Bill w Tier 2 discount (20%)	$678.15
Bill w Tier 3 discount (15%)	$720.54

[10] Coalition/300, Fain/15-17.

[11] Coalition/300, Fain/15-16.

Table 2 – Average Benefit Amount from Existing Low-Income Programs

Program	Average benefit (past 3 program years)
OLGA	$385
GAP	$111
LIHEAP	$319

To further illustrate the impact of how these programs can be combined, consider the following examples in Table 3 from customer accounts in the current 2021-2022 program year:

Table 3 – Energy Assistance Examples from Customer Accounts - 2021-2022

Programs accessed	Details
OLGA	Account: 315xxxx-0 • Balance on 3/23/22 bill $605.36 includes $476.69 past due • SEI Community Services pledged $600.00 OLGA grant
LIHEAP	Account: 374xxxx-0 • Balance on 4/15/22 bill $978.68 includes $848.19 past due. • Community Action Organization provided $849.00 LIHEAP
LIHEAP & OLGA & GAP & ARPA Combo (ARPA - American Rescue Plan Act)	Account: 376xxxx-6 • Past due balance $1,782.08 • Mid-Willamette Valley Community Action pledges $855.00 OLGA, $150.00 GAP, $355.00 LIHEAP, and $355.00 ARPA.
ARPA & OLGA Combo (ARPA - American Rescue Plan Act)	Account: 196xxxx-6 • Balance on 12/13/21 bill $350.44 includes $227.03 past due. • Customer received $200.00 OLGA from Community Action Team, and $100.00 ARPA
LIHEAP & OLGA & ARPA Combo (ARPA - American Rescue Plan Act)	Account: 334xxxx-4 • Balance on 1/10/22 bill $1,622.57 includes $1,427.45 past due. • Received $830.00 OLGA, $330.00 LIHEAP and $330.00 ARPA

The examples in Table 3 illustrate the effectiveness of combining energy assistance programs to help customers facing past due balances. The introduction of NW Natural's Low-Income Bill Discount Program provides another means to reduce customers' energy burdens and complements existing energy assistance programs. In addition, the proposed Low-Income Bill Discount Program would serve to reduce overall energy bills, which reduces any amount of energy assistance that would be needed and makes energy assistance budgets stretch further, and thus makes it possible to reach more customers.

Finally, the Company's Low-Income Bill Discount Program is not designed or intended to specifically insulate low-income customers from future rate increases. However, together with the other existing energy assistance programs, NW Natural is working to mitigate the impacts of the rate increase and reduce low-income customers' energy burden.

Q. The Coalition urges that the Commission should consider the rate increase in light of the reasons why the Company is asking for a rate increase, and compares the funding for the Low-Income Bill Discount Program ($7.4 million) to the amount of executive compensation and bonuses included in the case ($11 million).[12] How do you respond?

A. The Coalition's comparison does not accurately represent the Company's proposal for the Low-Income Bill Discount Program. The $7.4 million figure was provided as NW Natural's rough estimate of the potential annual cost of the program if all

[12] Coalition/300, Fain/18.

qualifying customers were to enroll in the program. To be clear, the $7.4 million was not intended to be a cost cap.

Q. The Coalition also provides testimony regarding the energy burden for low-income Oregonians, which is based on a report published by the Oregon Department of Energy ("ODOE").[13] Do you have any comments about that the Coalition testimony summarizing the ODOE report?

A. We appreciate the additional insight as it relates to energy burden across the entire State. This will be informative as NW Natural develops the LINA, which is specifically developed for NW Natural's service territory. NW Natural expects to better understand the energy burden of the Company's customers after completing the LINA, which in turn will help inform the permanent low-income rate program and any next iteration of the Low-Income Bill Discount Program. We will continue to work with our stakeholders throughout these processes.

IV. <u>RESIDENTIAL CUSTOMER DEPOSITS</u>

Q. What is CUB's position regarding residential deposits?

A. CUB recommends that the Commission provide direction to the Company such that "after the effective date of this general rate case, NW Natural will no longer collect residential customer deposits."[14] To implement this direction, CUB also "requests that the Commission order NW Natural to remove all rules from its tariff book that reference collecting deposits from residential customers."[15]

[13] Coalition/300, Fain/12.

[14] CUB/100, Jenks/27.

[15] CUB/100, Jenks/27.

Q. What is CUB's rationale for proposing that NW Natural cease collecting residential deposits?

A. CUB states that natural gas bills are highly seasonal, which makes it more difficult for low-income customers to afford additional charges on top of winter heating bills.[16] CUB further argues that the residential deposits are targeting the most vulnerable, and exacerbate the impacts of the housing crisis in Oregon.[17] Additionally, CUB comments that in response to the COVID-19 pandemic, the Commission directed utilities to cease charging deposits and to apply previously collected deposits to arrearages, so CUB claims that it should not be a significant change for NW Natural.[18] Finally, CUB points out that in Oregon, Cascade, PGE, and Avista have stopped collecting deposits for new customers, though Avista still charges deposits to certain existing customers.[19]

Q. How do you respond to CUB's proposal to eliminate residential customer deposits?

A. NW Natural does not support CUB's proposal to entirely eliminate residential customer deposits. The Company proposes instead to eliminate residential customer deposits for residential customers that self-certify as low-income customers. I will first provide context explaining why NW Natural believes it is not appropriate to cease collecting customer deposits for all new residential

[16] CUB/100, Jenks/29.

[17] CUB/100, Jenks/28-30.

[18] CUB/100, Jenks/30-31.

[19] CUB/100, Jenks/31.

customers, and then will respond to the arguments that CUB has raised in its Direct Testimony. Finally, I also explain that it is my understanding that the Commission will soon be starting the formal phase of a rulemaking proceeding to update the Division 21 rules, and based on the informal stage of the rulemaking, it appears that the most recent proposals mirror NW Natural's proposed approach, which would eliminate deposits for residential customers that self-certify as low-income.

Q. Please explain why NW Natural collects deposits from residential customers.

A. NW Natural provides natural gas to our customers prior to receiving payment for that gas. For each billing cycle, NW Natural reads the meter and bills the customer for gas that was used in the prior month. This practice means that NW Natural is extending credit to each customer every month by allowing for the usage of natural gas, prior to the customer paying for it. Because we are extending credit to our customers each month, NW Natural evaluates creditworthiness during the application process for customers. If a residential customer cannot prove creditworthiness during the application process, NW Natural charges a deposit.

Q. How does NW Natural determine creditworthiness for customers?

A. There are various ways that residential customers can prove creditworthiness and avoid paying a deposit, which are summarized in the list below:

- At least 12 months of prior service (during the past 24 months) with NW Natural, with a "Good" credit rating;[20]

[20] Credit history for commercial service may not be used to waive a deposit for a residential account.

- At least 12 consecutive months (during the past 24 months) of utility service of the same type applied for;
- Employment during the entire 12 months previous to the application by person(s) responsible for payment on the account;
- Regular income from a verifiable alternate source. Regular, consistent income can be: (1) Temporary Assistance for Needy Families ("TANF"); (2) Social Security Income; (3) Temporary Agencies; (4) Self-employment; (5) Retirement; (6) Trust fund;
- Signed Surety Agreement returned within five business days; or
- The account has an existing Landlord Between Tenant contract on file for the premise in question, which is a contract between NW Natural and the landlord that allows NW Natural to put the gas service in the landlord's name after the tenant moves out.

The Company also considers factors that may demonstrate unsatisfactory credit, such as:

- The applicant or customer is unable to establish satisfactory credit in one of the ways listed above.
- The applicant or customer received service from any Oregon regulated energy utility within the past 24 months and did not pay their balance in full when service was terminated.
- The applicant or customer was previously terminated by any Oregon regulated utility for theft or for tampering with the meter or other utility facilities.

- The applicant has filed for bankruptcy within the past six years and included NW Natural debts.
- The applicant is an estate or trust. An estate or trust may not avoid a deposit by sending a signed Surety Agreement.

If an Oregon residential applicant meets any of the requirements for establishing creditworthiness and does not meet any criteria for unsatisfactory credit, no deposit is required. If the customer is unable to establish creditworthiness through one of the mechanisms discussed above, they are charged a deposit or must provide a surety agreement.

Q. Does NW Natural refund customer deposits after the customer establishes creditworthiness through timely payment?

A. Yes. After the customer establishes creditworthiness, NW Natural refunds the customer deposit, including interest at a rate specified by the Commission. The refund occurs after the customer has 12 months of good payment history, and then the deposit will be refunded in the 13th month. Having good payment history means receiving no more than two urgent final shut-off notices during the 12-month period.

Q. How much is a typical residential deposit?

A. The residential deposit is equivalent to one-sixth of the annual estimated billings based on prior usage at the premises or based on time and size of the equipment installed at the premises, which roughly equates to two months of service. The average Oregon residential deposit in 2018/2019 was $93.

Q. Does the customer have to pay the deposit amount all at once?

A. No. If the customer cannot pay the deposit all at once, they have an option to pay it in three installments over the course of three months.

Q. How does NW Natural use the deposits?

A. The deposit is a mechanism that the Company uses to prevent write-offs and minimize its uncollectible expense. In the event a customer closes their account without paying it off in full, the Company will use the deposit on the customer's account to avoid having to send the account to collections. By using the deposit to help with the closing balance, NW Natural avoids socializing the potential write-offs to the rest of our customer base.

Q. Do you think the practice of collecting customer deposits is reasonable?

A. Yes. Fundamentally, the practice of collecting customer deposits serves to reduce the level of uncollectible expense, which in turn, reduces contributions from other customers. Additionally, NW Natural holds the customer deposit until the customer establishes creditworthiness, and then returns the deposit to the customer with a Commission-approved interest rate so that the customer is receiving fair financial treatment while the Company is holding their money.

Q. How does the collection of customer deposits compare to other tools to incentivize timely payment of utility bills?

A. In comparison with the other tools available, such as disconnection and reconnection, or taking the customer to collections, the deposit process is the least punitive to the customer, as the customer may make the payment in installments and has the opportunity to have the deposit refunded with interest.

Q. Is NW Natural currently collecting customer deposits?

A. No. In response to the COVID-19 pandemic, NW Natural, other Oregon utilities, Staff, and stakeholders entered into a Stipulated Agreement ("COVID-19 Stipulation"), which the Commission subsequently approved in November 2020, agreeing that utilities suspend the collection of residential customer deposits.[21] The COVID-19 Stipulation provides that utilities may resume collecting residential customer deposits after October 1, 2022.[22] NW Natural plans to resume collecting customer deposits from new customers at that time.

Q. When NW Natural was routinely collecting customer deposits, about what percentage of new customers were required to pay a deposit?

A. As shown in Table 4, below, in 2019, 9.92 percent of new customers were required to pay a deposit. In 2018, 7.83 percent of customers were required to pay a deposit.

Table 4 – Oregon Residential Deposits Charged to New Customers[23]

Oregon Residential Deposits charged to New Customers			
Year	**# of Deposits Charged**	**# of Opening Bills**	**Percent of Customers**
2018	6,516	83,256	7.83%
2019	8,043	81,106	9.92%

[21] *In the Matter of Comm'n Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket UM 2114, Order No. 20-401, App. A at 14 (Nov. 5, 2020).

[22] *Id*.

[23] The data provided in Table 2 is for new customers; there are also circumstances such as a reconnection after a disconnection for non-payment in which an existing customer may be required to pay a residential customer deposit.

Q. CUB asserts that charging customer deposits is targeting the most vulnerable populations. How do you respond?

A. We attempted to analyze this assertion by identifying customers in 2018 and 2019 (pre-pandemic) who were required to pay customer deposits, and we compared that against customers who received energy assistance in the prior 24 months. CUB has not defined "vulnerable populations" in its Direct Testimony, and we recognize that the comparator we are using may not fully capture CUB's intent, but it is meant to be illustrative of the customers paying deposits. As shown in Table 5, below, of the 15,399 deposits collected from our customers in 2018, 9 percent were collected from low-income customers.[24] In 2019, 8 percent of our deposits were collected from low-income customers.

Table 5 - Oregon Residential Deposits & Low-Income Customers

2018	Low Income	# of Customers	Amount Paid	% of Customers
	No	13,964	$ 1,227,716	91%
	Yes	**1,435**	**$ 127,006**	**9%**
	Totals:	15,399	$ 1,354,722	
2019	Low Income	# of Customers	Amount Paid	% of Customers
	No	13,542	$ 1,160,647	92%
	Yes	**1,133**	**$ 99,284**	**8%**
	Totals:	14,675	$ 1,259,931	

Q. How do deposits help mitigate the Company's uncollectible expense?

A. A deposit held on the account is credited to the account ledger on the closing bill, which reduces the outstanding amount owed on the closing bill. If the closing bill

[24] For this analysis, NW Natural identified low-income customers as those who had previously signed up for energy assistance programs in the past 24 months. For security and privacy reasons, NW Natural does not maintain income data for its customers.

is not paid it goes through the closed account collection process and is eventually written-off. As shown in Table 6 below, in a pre-pandemic year, on average NW Natural would collect $1.3 million in deposits from our Oregon residential customers. On average, the Company would write-off $1.4 million from our residential customer base.

Table 6. Comparison of Deposits Collected and Uncollectible Expense

Year	# of Customers	Deposits Collected	Write-Off
2017	15,699	$ 1,375,482.24	$ 1,653,297
2018	15,399	$ 1,354,721.97	$ 1,390,881
2019	14,675	$ 1,259,930.33	$ 1,268,354
3-Year Average	15,258	$ 1,330,044.74	$ 1,437,511

Q. Please provide detail regarding the customer deposits currently held by the Company.

A. During the pandemic, the COVID-19 Stipulation allowed NW Natural to apply a customer's deposit to their account to reduce their overall balance. This was done to help take the pressure off customers and reduce the amount they owed, in order to help with the overall financial burden that came along with the pandemic. Additionally, this approach was applied to our entire residential, commercial, and industrial customer base.

The application of deposits was effective in immediately reducing the strain on the customer, and it was helpful in the short-term to reduce overall accounts receivable. On the other hand, this approach also left the Company more exposed to write-off expenses in the long-term. At year-end 2019, NW Natural held $4.6 million in deposits for our entire customer base. At year-end 2021, NW Natural held $1.4 million in deposits; that is a reduction of $3.2 million in the amount of deposits we hold. As a result, this means that there are increased numbers of customers that have not established creditworthiness, with no deposit on their account, which increases the likelihood that balances on unpaid accounts will be higher, which will ultimately be reflected in higher uncollectible expense.

Q. CUB asserts that because NW Natural has already temporarily ceased collecting customer deposits in response to the COVID-19 pandemic, it should not be a significant change to permanently cease collecting customer deposits.[25] How do you respond?

A. I disagree. NW Natural believes that the sharp drop in the amount of deposits held as a result of the temporary pause on collecting customer deposits has the potential to have an impact on our write-offs now and in the future. While it is still too early to assess the impacts from the reduction in customer deposits, the Company disagrees that there will be no significant impact associated with permanently eliminating residential deposits.

Q. Is NW Natural's approach to customer deposits consistent with the Commission's rules?

A. Yes. The Commission has long-standing rules defining the policies and procedures for customer deposits in Chapter 860, Division 21. NW Natural's current approach follows the Commission's rules.

[25] CUB/100, Jenks/30-31.

Q. Is there currently a rulemaking underway to update the Division 21 rules?

A. Yes. The Commission initiated a rulemaking, docket AR 653, to consider potential revisions to the Division 21 rules. The rulemaking is in the informal stage, however the proposals that have been shared most recently include an approach similar to NW Natural's proposal, which is to eliminate the collection of customer deposits from low-income customers.[26] NW Natural and the other utilities participating in the proceeding have supported the proposal to eliminate the collection of residential customer deposits from low-income customers.

Q. CUB is urging that all customer deposits should be eliminated and points to the fact that Cascade, PGE, and Avista have completely or partially ceased to collect customer deposits. How do you respond?

A. NW Natural acknowledges that certain peer utilities have opted to cease collecting customer deposits, either entirely or for new customers. However, the Commission has not yet made a policy determination that all utilities should cease collecting customer deposits permanently, or that the uncollectible expense that may be defrayed by application of customer deposits should instead be socialized among all customers. This would be a major policy shift, and NW Natural continues to believe that the collection of customer deposits is an important tool to help avoid the collections process and to mitigate the overall level of uncollectible expense.

[26] *See In the Matter of Revisions to Division 21 Rules to Strengthen Customer Protections Concerning Disconnections*, Docket AR 653, Staff Report (June 2, 2022).

Q. If the Commission were inclined to consider CUB's proposal, should it do so in this case?

A. No. We should not change one credit practice in isolation of the utility's other credit practices or the credit practices of the other utilities. If the Commission were persuaded that CUB's proposal warrants further consideration, the best place to do so would be in the Division 21 rulemaking proceeding (or a related policy docket) that would consider the credit and collections process holistically for all energy utilities with the other interrelated elements, such as late fees and notices, disconnection fees and notices, reconnection fees and reconnection process. By taking a holistic approach, we can better ensure that we have a set of credit and collection practices that balance the policies of HB 2475, the responsibility for a customer to satisfy their payment obligations, and the upward pressure on uncollectible expense.

Q. Will NW Natural commit in this rate case to ceasing collection of customer deposits for residential customers who self-certify as low-income?

A. Yes. To the extent that NW Natural's rate case is completed in advance of the revision to the Division 21 Rules in docket AR 653, NW Natural will commit, as of the rate effective date in this rate case, to not requiring residential customers who self-certify as low-income to pay a deposit.

Q. Please summarize your recommendation regarding customer deposits.

A. While NW Natural is sympathetic to the concerns that CUB has raised, ultimately, the utility still needs to have tools available that will incentivize timely payment of bills. NW Natural's proposal, which is to eliminate the collection of customer deposits for low-income customers, strikes an appropriate balance and is consistent with the current direction for the Division 21 rulemaking proceeding.

V. SCHEDULE 198 BENEFITS BOTH THE CUSTOMERS & THE COMPANY

Q. Please summarize why AWEC opposes the Company's proposed RNG automatic adjustment clause, Schedule 198.

A. AWEC states that "existing regulatory mechanisms, including the general rate case process and the utility's general ability to request deferrals, already provides NW Natural with the ability to recover all prudently incurred investments made with respect to the RNG program."[27] While ORS 757.394 and ORS 757.396 require that the Company recover all of its prudently incurred costs associated with RNG investments, AWEC states that it is possible for NW Natural to recover all of its prudently incurred costs without Schedule 198. Therefore, AWEC believes that Schedule 198 is "not necessary."[28]

Q. By focusing only on whether Schedule 198 is absolutely necessary to recover prudently incurred costs, does AWEC ignore the substantive benefits of Schedule 198 to both the Company and its customers?

A. Yes. AWEC ignores the benefits of Schedule 198, only saying that "[s]ingle issue ratemaking in general is beneficial to shareholders and harmful to customers."[29]

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[27] AWEC/100, Mullins/39.

[28] *Id.*

[29] *Id.* at 40.

Q. What are the benefits of Schedule 198?

A. As I stated in my Direct Testimony, Schedule 198 has three principal benefits. First, allowing NW Natural to recover costs through Schedule 198 ensures that it will recover these costs in a timeframe that is consistent with customers receiving the benefits (RNG) of such projects.[30] To be clear, RNG will benefit our customers immediately, whether the costs be associated with investments in infrastructure (as soon as they are placed in service) or offtake agreements (as soon as the first therm is purchased). Timely cost recovery through Schedule 198 will best match benefits and costs. Moreover, while such cost recovery is, of course, beneficial to the Company, Staff states that there are customer equity benefits as well.[31]

Second, timely recovery of costs through Schedule 198 prevents the accumulation of substantial deferrals between general rate cases, which would be required if NW Natural were to follow AWEC's approach of only using general rate cases to recover the costs of its qualified investments.

Finally, unlike a general rate case, NW Natural will make an annual filing that updates each RNG project's revenue requirement, including a reduction in rate base due to depreciation. If NW Natural only used general rate cases to recover these costs, these reductions to rate base would not be reflected in rates annually, but rather only when NW Natural has a general rate case. This annual reduction in rate base benefits customers and is a major reason why CUB supports

[30] NW Natural/1500, Kravitz/6.

[31] Staff/1700, Muldoon/24.

using an AAC in this instance.[32] In explaining why CUB is not proposing to have NW Natural recover its RNG qualified investments through a general rate case, CUB states that it "recognizes the customer value of updating the revenue requirement of RNG projects for accumulated depreciation on an annual basis, which is not possible under a traditional ratemaking approach."[33]

Q. You have explained the substantive benefits of Schedule 198, but AWEC also asserts that there are no procedural benefits.[34] Is AWEC correct?

A. No. There are procedural efficiencies to recovery through Schedule 198 as opposed to recovery through a general rate case—a point on which Staff agrees, stating that a Schedule 198 proceeding would be more streamlined than general rate cases.[35]

In addition, CUB supports an RNG AAC, albeit with several substantive differences from what the Company has proposed, because of the procedural benefits. In its Direct Testimony, CUB states that its proposed RNG AAC "enables annual rate changes to minimize the regulatory burden associated with renewable natural gas procurement in order to avoid imposing a burdensome review process on the Commission, Commission Staff, and consumer advocates."[36] Again, although the Company disagrees with CUB on several of its proposals regarding

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[32] Under Schedule 198, NW Natural will also update operating expenses to accurately reflect the costs of operating the RNG plant.

[33] CUB/200, Gehrke/25.

[34] AWEC/100, Mullins/40.

[35] Staff/1700, Muldoon/24.

[36] CUB/200, Gehrke/27.

the RNG AAC, we do agree about the procedural benefits. AWEC's argument that an AAC "would still require a filing well in advance of the rate effective date, along with an evidentiary review process"[37] overlooks the fact that the Schedule 198 process is faster than a general rate case and that a streamlined process is necessary in this instance because, as stated by CUB in support of an RNG AAC, "[the] Company will be making significant investments over the next decade to procure RNG to comply with CPP and SB 98."[38]

Q. AWEC states that an AAC would consider cost allocation and that it is unreasonable to do so outside of a general rate case.[39] How do you respond?

A. Since an AAC is a form of ratemaking—and ratemaking, by definition, involves cost allocation—AWEC appears to be arguing that all AACs are unreasonable. However, the Commission's statutes specifically contemplate that certain costs may be best suited for recovery through AACs,[40] and the Commission has historically adopted them to ensure timely cost recovery where it deems appropriate, such as the PGA.[41] More specifically, NW Natural continues to believe that RNG costs should be allocated to those customers that benefit from

[37] AWEC/100, Mullins/40.

[38] CUB/200, Gehrke/27.

[39] AWEC/100, Mullins/40-41.

[40] ORS 757.210.

[41] *See e.g. In re Northwest Natural Gas Company, dba, NW Natural, Request for Amortization of Certain Deferred Accounts Related to Gas Costs, Schedules P, 162, 164*, Docket UG 432, Order No. 21-376 (Oct. 28, 2021) ("The PGA mechanism was originally established by Order No. 89-1046 to minimize the frequency of gas cost-related rate changes and the fluctuation of rate levels pursuant to ORS 757.259(2)(e)."). *Id.* at App. A at 2.

them. Because NW Natural is the point of regulation for both its sales and transportation customers for the CPP, both types of customers benefit from NW Natural acquiring RNG and, therefore, both sales and transportation customers should bear these costs.[42]

Q. AWEC requests that the Commission open a docket to evaluate a comprehensive ratemaking mechanism to address CPP compliance costs.[43] Do you support AWEC's request?

A. Yes. NW Natural acknowledges that the CPP raises several new issues regarding cost allocation, such as how such costs can be equitably allocated and whether the economy-wide impacts of fully imposing CPP compliance costs on large industrial customers should be considered in ratemaking. These questions are urgently in need of answers.

Q. Should such a cost allocation docket prevent the Commission from adopting Schedule 198 in this proceeding?

A. No. As written, Schedule 198 does not require a particular form of cost allocation and it will ultimately reflect the Commission's policy on that issue. That said, as I have previously explained, NW Natural believes that RNG costs should be allocated to both sales and transportation customers. Moreover, the Commission should not delay action on Schedule 198 because the CPP is currently in effect and NW Natural must incur costs to comply with it. Schedule 198 allows NW

[42] *See* NW Natural/1500, Kravitz/13.

[43] AWEC/100, Mullins/43.

Natural to recover a subset of these costs, qualified investments in RNG infrastructure, in a manner that benefits both the Company and its customers.

VI. RESPONDING TO PROPOSED SCHEDULE 198 ALTERNATIVE

Q. Please describe CUB's proposed alternative to Schedule 198.

A. In its testimony, CUB presents the following alternative to Schedule 198:

- All costs associated with RNG qualified investment will be tracked separate from base rates in the renewable gas cost recovery mechanism.
- NW Natural will file to update RNG costs using a forward test year on February 28th of each year. The rate effective date for the update filing mechanism will be November 1st.
- NW Natural will only be allowed to add new RNG assets on November 1st of each year.
- NW Natural will include the projected revenue requirement associated with new RNG assets and will annually update the forecasted cost of previously approved RNG projects in rates. Capital investments will be subject to recovery based on the undepreciated balance as of the rate-effective date.
- Prior to changing rates on November 1st, NW Natural will attest that all RNG projects are currently operating and providing utility service to Oregon customers. If a project is no longer producing and is retired while there is still undepreciated capital investment associated with the project, NW Natural will remove that project from its calculation of its return on rate base from the mechanism and will earn the time value of money on its undepreciated capital investment. Once NW Natural meets the cost cap established in SB 98, CUB

proposes that NW Natural, intervenors, and Commission Staff will timely meet to discuss changes to the mechanism, and how ratemaking for RNG should occur after the cost cap is reached.

- The Company will not be allowed to file for a deferral between the in-service date of the RNG project and the rate effective date.
- The Company will be allowed to defer differences between forecasted and historical RNG costs and actual RNG costs, subject to an earning test. The earnings test eliminates any annual RNG cost adjustment if the Company earns within plus/minus 100 points of its allowed return on equity (ROE).[44]

Some of CUB's proposals are identical to the Company's proposed Schedule 198, whereas others are different. I will address each in turn, as well as address AWEC's specific proposals regarding deferrals if, despite its arguments to the contrary, Schedule 198 is nonetheless adopted.

Q. Do you agree that all costs associated with RNG qualified investment should be tracked separately from base rates in the RNG AAC?

A. Yes. Schedule 198, as attached to my Direct Testimony, already states that all costs associated with RNG qualified investments will be tracked separately from base rates.[45]

[44] CUB/200, Gehrke/24-25.[45] *See* NW Natural/1501, Kravitz.

[45] *See* NW Natural/1501, Kravitz.

Q. Do you agree that NW Natural should file updated RNG costs using a forward test year on February 28th of each year?

A. No. Although I proposed making a filing for new RNG qualified investments by February 28th of each year, I continue to believe that NW Natural should make a filing that updates the cost of service for existing RNG qualified investments by August 1st of each year. Filing updates to RNG costs by August 1st of each year allows NW Natural to have a better, more accurate forecast for the upcoming test year of operating expenses, as well as commodity costs. In instances where NW Natural is selling the physical gas while retaining the environmental attributes to meet ORS 757.396 targets and CPP compliance obligations,[46] an accurate view of the price of conventional natural gas is important in determining the RNG project's investment for the coming year because the revenue from these physical gas sales offsets the cost of that project. Therefore, having a more accurate forecast reduces deferral amounts between rate cases, minimizing the amount that rates change from year-to-year.

Q. Do you agree that rates should only be allowed to change on November 1st of each year?

A. No. Under Schedule 198, NW Natural anticipates that rates will change on November 1st to reflect new RNG qualified investments, as well as updates to costs of existing RNG qualified investments.[47] However, NW Natural believes that

[46] *See* NW Natural/1100, Chittum/5-6 (discussing how environmental attributes are used to meet ORS 757.396 targets and for CPP compliance).

[47] NW Natural/1501, Kravitz/2.

having the flexibility to use a date other than November 1st makes sense if it "can demonstrate it is in the public interest" to do so.[48] Having some flexibility will allow both NW Natural and stakeholders to respond to changes in circumstances that may happen in the future and that cannot be anticipated. For example, CUB's proposal to use November 1st is based on the assumption that the Company's other rate changes, either due to a general rate case or the PGA, also take place on November 1st.[49] CUB states that using a fixed November 1st date will "minimize the frequency of rate changes borne by customers and align customer rate changes for conventional natural gas with changes with renewable natural gas."[50] While this is the current process and NW Natural has no plans to seek changes to it, there is no guarantee that November 1st will always be used for either general rate cases or the PGA in all years going forward. If these rate adjustments do not take place on November 1st, for whatever reason, then there would be multiple rate adjustments in a given year (i.e., one rate change due to either a general rate case or PGA and one rate change due to Schedule 198). These multiple rate changes in a single year would achieve the exact opposite of CUB's stated goal of minimizing the frequency of rate changes. While the Company continues to anticipate making rate changes on November 1st, there should be some degree of flexibility to prevent the unanticipated consequences of using a single, immovable date.

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[48] *Id.*

[49] CUB/200, Gehrke/24.

[50] *Id.*

Further, as stated in the Company's Direct Testimony, having flexibility in the rate effective date may prevent the accumulation of a substantial deferral balance if, for example, a qualified investment entered service on November 7th, and was not included in rates until the following November 1st.[51] While CUB opposes allowing the Company to defer RNG qualified investments between their in-service date and their rate effective date, NW Natural continues to believe such deferrals are warranted, as explained in further detail below. Even if such deferrals are permitted, allowing the Company to use a rate effective date other than November 1st would minimize deferral balances in certain instances.

Q. CUB proposes that NW Natural will include the projected revenue requirement associated with new RNG assets and will annually update the forecasted cost of previously approved RNG projects in rates. Capital investments will be subject to recovery based on the undepreciated balance as of the rate-effective date. Do you agree?

A. Yes. CUB's proposal reflects Schedule 198 that the Company filed with its Direct Testimony. Under Schedule 198, NW Natural will include the projected revenue requirement of new RNG assets and will annually update the forecasted cost of previously approved RNG projects in rates. Also, the Company agrees with CUB that capital investments will be subject to recovery based on the undepreciated balance as of the rate-effective date.

[51] NW Natural/1500, Kravitz/10.

Q. CUB proposes that prior to changing rates on November 1st, NW Natural will attest that all RNG projects are currently operating and providing utility service to Oregon customers. Do you agree?

A. Yes. NW Natural is willing to provide such an attestation.

Q. CUB states that if an RNG project is no longer producing and is retired while there is still undepreciated capital investment associated with the project, NW Natural should remove that project from its calculation of its return on rate base and earn the time value of money on its undepreciated capital investment. Do you agree?

A. NW Natural believes that CUB's proposal generally reflects Oregon precedent on this issue, which will be addressed in legal briefing. If such a situation were to occur, however, the "time value of money" should be NW Natural's long-term debt financing cost for the facility.

Q. CUB recommends meeting to discuss changes to the RNG AAC if the cost cap in ORS 757.396 is reached. Do you agree?

A. Yes, I generally agree that Schedule 198 should be re-examined after some period of time. In my Direct Testimony, I proposed that the parties meet within three years to evaluate Schedule 198.[52] The Company, however, would be willing to accept CUB's recommendation to discuss changes to Schedule 198 if the cost cap in ORS

[52] NW Natural/1500, Kravitz/13.

757.396 is reached,[53] so long as there are not multiple review timelines. In other words, the Company would accept either meeting within the first three years to evaluate Schedule 198 _or_ if the ORS 757.396 cost cap is reached, but not both. The Company believes that having multiple timelines would lead to duplicative and unnecessary process.

Q. With the exception of the Lexington RNG project, CUB proposes that the Company not be allowed to file for a deferral between the in-service date of the RNG project and the rate effective date. AWEC agrees that such deferrals should not be part of Schedule 198.[54] Why should such deferrals be permitted?

A. While the Company appreciates CUB's support of its Lexington deferral, it continues to believe that it should be allowed to defer costs of all RNG projects between the in-service date of the RNG project and the rate effective date. CUB's own testimony shows why these deferrals are necessary to ensure that NW Natural recovers all of its prudently incurred costs, as required under ORS 757.394 and ORS 757.396. In the absence of a deferral, CUB states that the Company is subject to regulatory lag between the in-service date of the RNG project and the rate effective date.[55] CUB defines "regulatory lag" as "***costs that a utility cannot***

[53] Per ORS 757.396(5), NW Natural would need to obtain Commission approval of additional qualified investments if the difference between the total (or "all-in") levelized annual cost of the utility's RNG portfolio and the all-in levelized annual cost of the same quantity of conventional natural gas (i.e., the incremental cost of RNG) exceeds 5 percent of a natural gas utility's annual revenue requirement. The "all-in" cost reflects the total cost for a unit of natural gas, not just the gas commodity cost.

[54] AWEC/100, Mullins/41.

[55] CUB/200, Gehrke/26.

recover in rates between general rate cases (GRC), and during a tariff investigation."[56] If the Company cannot recover a certain type of prudently incurred costs in rates, then it cannot, by definition, recover all of its prudently incurred costs as required by ORS 757.394 and ORS 757.396. As CUB, itself, stated in a prior proceeding: "A plain reading of this language [ORS 757.396] demonstrates that the Commission is mandated (i.e. 'shall') to adopt ratemaking mechanisms to ensure recovery of the utility's prudently incurred costs."[57] AWEC states that SB 98[58] did not specifically authorize NW Natural to "defer investment costs associated with the RNG programs,"[59] but ignores the fact that without a deferral NW Natural would not be able to recover these costs. Moreover, in a prior proceeding, AWEC, itself, stated that: "The law [SB 98, including ORS 757.394 and ORS 757.396] is clear that utilities will be able to recover all prudently incurred cost associated with an RNG program."[60]

Furthermore, NW Natural continues to believe that such deferrals are necessary to ensure that Schedule 198 is balanced. CUB states that regulatory lag also "refers to the excess accumulated depreciation that customers fund when capital assets depreciate but are still being recovered by the utility at the figure

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[56] *Id.* (Emphasis added).

[57] *In re Rulemaking Regarding the 2019 Senate Bill 98 Renewable Natural Gas Programs*, CUB Comments, Docket AR 632 at 2 (Apr. 27, 2020) (available at: https://edocs.puc.state.or.us/efdocs/HAC/ar632hac162912.pdf).

[58] ORS 757.390 through 757.398.

[59] AWEC/100, Mullins/41.

[60] *In re Rulemaking Regarding the 2019 Senate Bill 98 Renewable Natural Gas Programs*, AWEC Comments, Docket AR 632 at 2 (Apr. 27, 2020) (available at: https://edocs.puc.state.or.us/efdocs/HAC/ar632hac123649.pdf).

from its previous [general rate case]."[61] In addition to deferring the costs of RNG projects between the in-service date of the RNG project and the rate effective date, the Company will also, as CUB states, "update the revenue requirement of RNG projects for accumulated depreciation on an annual basis, which is not possible under a traditional ratemaking approach."[62] By reducing the lag between updates, Schedule 198 benefits customers by incorporating this reduction of rate base into rates every year, as opposed to only when the Company concludes a general rate case. This results in the Company's proposal reducing both types of regulatory lag that CUB identifies, thereby ensuring that Schedule 198 is appropriately balanced. Only reducing one type of regulatory lag, as CUB suggests, is a narrow view that does not appropriately balance the Company's and its customers' interests.

Finally, if the Company cannot recover the cost of RNG projects between the in-service date and the rate effective date, rates would not reflect the costs of compliance with the CPP for the RNG produced at the facility between the in-service date and the rate effective date.

[61] CUB/200, Gehrke/26.

[62] CUB/200, Gehrke/25.

Q. AWEC believes that if a deferral is approved for RNG projects in service prior to the rate effective date, then an earnings test should be applied that is equal to 100 basis points less than NW Natural's authorized ROE.[63] Why is an earnings test less than NW Natural's authorized ROE inappropriate and bad public policy?

A. First, we do not understand why AWEC would seek such an extraordinarily punitive approach to recovery of RNG investments needed to meet the milestones of SB 98 and the CPP. Senate Bill 98 (ORS 757.390-398) was meant to incentivize the acquisition of RNG, and an earnings test that is 100 basis points *below* the authorized ROE does the exact opposite. Furthermore, the Company anticipates that RNG will be a growing piece of our decarbonization portfolio, and this proposal will strip away our opportunity to earn a fair rate of return for the Company and lead to perpetual under-earning for the Company.

Additionally, an earnings test that is 100 basis points less than NW Natural's authorized ROE is inconsistent with both ORS 757.394 and ORS 757.396, which requires that NW Natural recover all of its prudently incurred costs. Under AWEC's proposal, NW Natural would only be able to fully recover its prudently incurred costs if its ROE were 100 basis points less than its authorized ROE. ORS 757.394 and ORS 757.396, however, allow NW Natural to recover all of its prudently incurred costs, even if it is not under-earning by 100 basis or more. In addition, AWEC's proposal is inconsistent with ORS 757.396(3), which requires recovery of

[63] AWEC/100, Mullins/42.

"the cost of capital established by the commission in the large natural gas utility's most recent general rate case."

Q. If Schedule 198 is ultimately approved, AWEC opposes allowing the Company to defer the differences between forecasted RNG costs and actual RNG costs.[64] Why are such deferrals necessary?

A. As I stated in my Direct Testimony, such deferrals are necessary in order to true-up the actual costs incurred through the course of the year and will ensure that the difference between forecasted and actual costs can be recovered in rates, as well as the difference between forecasted and actual revenues received for recovery. Again, for at least some of NW Natural's RNG projects, such as Lexington, NW Natural will be selling the physical gas the project produces while retaining the environmental attributes to meet ORS 757.396 targets and CPP compliance obligations. Since the market price of natural gas varies over the course of the year and is outside the control of the Company, truing up these costs so that it accurately reflects the benefit to customers makes sense. Similarly, truing up RNG projects' other operating costs will ensure that these costs are accurately reflected as well. Finally, truing up the RNG operating costs ensures that the Company recovers all of its prudently incurred costs consistent with ORS 757.394 and ORS 757.396 as described above.

[64] AWEC/100, Mullins/42.

Q. If the Company is permitted to defer the differences between forecasted RNG costs and actual RNG costs, CUB proposes an earnings test that would "eliminate[] any annual RNG cost adjustment if the Company earns with plus minus 100 points of its allowed return on equity (ROE)."[65] How do you understand this earnings test to work?

A. My understanding is that the earnings test would be a historical lookback where the Company would not amortize any differences between forecasted RNG operating costs/revenues[66] and actual RNG operating costs/revenues, unless NW Natural either: 1) exceeded its authorized ROE by 100 basis points (credit), or 2) under-earned its authorized ROE by 100 basis points (surcharge).

Q. Why is this type of earnings test inappropriate?

A. All of the concerns that I raised with AWEC's proposed earnings test for deferring the costs of RNG qualified investments between the in-service date and the rate effective date also apply here. Additionally, this type of earnings test would allow the Company to over-recover its forecasted costs if they were higher than actual, and the Company was earning less than 100 basis points over its authorized ROE. On the other hand, CUB's proposed earnings test band set at 100 basis points under authorized ROE will diminish the Company's opportunity to earn its authorized ROE. The Company does not believe that over- or under-recovery is appropriate for recovery of qualified investments. Rather, the recovery of prudent

[65] CUB/200, Gehrke/25.

[66] Some RNG projects, such as Lexington, involve selling the energy content of the gas to third parties and retaining the environmental attributes to meet ORS 757.396 targets and CPP compliance. The revenue from these sales to third parties offsets the cost of the project.

investments—no more, no less—is appropriate for the AAC, and that is how the Company proposed the mechanism.

Q. Please summarize where you agree with CUB's alternative RNG AAC.

A. CUB and NW Natural agree on the following issues:

- All costs associated with RNG qualified investment will be tracked separately from base rates.
- NW Natural will include the projected revenue requirement associated with new RNG assets and will annually update the forecasted cost of previously approved RNG projects in rates. Capital investments will be subject to recovery based on the undepreciated balance as of the rate-effective date.
- Prior to changing rates on November 1st, NW Natural will attest that all RNG projects are currently operating and providing utility service to Oregon customers. If a project is no longer producing and is retired while there is still undepreciated capital investment associated with the project, NW Natural will remove that project from its calculation of its return on rate base from the mechanism and will earn the time value of money on its undepreciated capital investment. As stated in my testimony above, this should reflect the Company's cost of long-term debt.
- Meeting to discuss the RNG AAC if NW Natural exceeds the ORS 757.396 cost cap. Again, NW Natural's support for this proposal is conditioned on only having one trigger to re-examine the RNG AAC.

Q. Please summarize where you do not agree with CUB's proposed RNG AAC.

A. CUB and NW Natural disagree on the following issues:

- Whether the Company can add new RNG assets on a date other than November 1st if it shows that it is in the public interest to do so.
- Whether the Company should file updated RNG costs for existing projects on February 28th, as proposed by CUB, or August 1st, as proposed by NW Natural.
- Whether the Company can file for a deferral between the in-service date of the RNG project and the rate effective date.
- Whether the deferral for differences between forecasted historical RNG costs and actual RNG costs should be subject to an earning test that eliminates any annual RNG cost adjustment if the Company earns within plus/minus 100 basis points of its allowed ROE.

In addition to these areas of disagreement, the Company disagrees with AWEC that any deferral between the in-service date of the RNG project and the rate effective date should be subject to an earning test that would prohibit cost recovery if the Company's ROE were equal to or exceeded its authorized ROE minus 100 basis points.

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VII. RESPONDING TO STAFF'S CONCERNS REGARDING SCHEDULE 198

Q. While Staff supports applying Schedule 198 to the Lexington RNG project and cites its positive aspects, it states that an AAC may not be appropriate for future RNG investments, given their complexity.[67] How do you respond?

A. NW Natural believes that its Schedule 198 will allow parties to focus their prudence review solely on the particular RNG investments at issue, which is not the case during a general rate proceeding where the Company is typically seeking recovery of numerous capital investments. Also, as noted above, Staff finds tangible benefits to Schedule 198 (a more streamlined process and annual reductions in rate base due to depreciation),[68] whereas its concerns with Schedule 198 are more abstract. The Company believes that the tangible benefits recognized by Staff outweigh these concerns, especially because it is unclear when, if ever, these concerns would be addressed. Finally, there would be better insight into the operations of existing RNG projects through an annual look, as provided in Schedule 198.

Q. Does Staff's summary of Schedule 198[69] reflect what the Company filed in its Direct Testimony?

A. Yes. NW Natural only has one small clarification. Staff requests that NW Natural make a filing by February 28th to recover costs of a new RNG project.[70] In

[67] Staff/1700, Muldoon/25.

[68] *Id.* at 24.

[69] *Id.* at 27-28.

[70] *Id.* at 27.

Schedule 198, which is attached to my Direct Testimony, NW Natural is already required to make a filing by February 28th in order to recover the costs of a new RNG project.[71]

Q. Does this conclude your Reply Testimony?

A. Yes.

[71] NW Natural/1501, Kravitz.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Reply Testimony of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1700

June 6, 2022

EXHIBIT 1700 – REPLY TESTIMONY – POLICY

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I. INTRODUCTION AND SUMMARY

Q. Ms. Heiting, please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Kimberly Heiting, and I am the Senior Vice President of Operations and Chief Marketing Officer at NW Natural.

Q. Please describe your education and employment background.

A. I received a Bachelor of Arts in Communications from the University of Iowa and a Master of Science in Communications from Northwestern University. I have worked at NW Natural since 2005 in leadership roles related to communications marketing, and operations with increasing responsibility. I have held my current position since 2018.

Q. Mr. Bracken, please state your name and position with NW Natural.

A. My name is Ryan Bracken, and I am Director of Strategic Planning at NW Natural.

Q. Please describe your education and employment background.

A. I have a Bachelor of Arts in Economics and Marine Science from the University of Hawaii at Hilo and a Master of Arts in Economics from Colorado State University. I have worked at NW Natural since 2014, and I have been in my current role since 2020. Prior to joining NW Natural, I was a senior economist at the Public Utility Commission of Oregon and an instructor of economics at the Colorado School of Mines, where I completed doctoral coursework in energy economics.

Q. Are you jointly sponsoring this Reply Testimony?

A. Yes, we are jointly sponsoring Sections II.A, II.B, II.C, and II.D of this testimony, and Ms. Heiting is individually sponsoring Section II.E.

Q. What is the purpose of your Reply Testimony?

A. Our Reply Testimony responds to testimony from the Oregon Citizens' Utility Board ("CUB") and Coalition of Communities of Color, Sierra Club, Verde, Climate Solutions, Oregon Environmental Council, Columbia Riverkeeper, and Community Energy Project (collectively, "the Coalition") regarding NW Natural's response to climate change, whether the Company can reduce its greenhouse gas ("GHG") emissions sufficiently to comply with Oregon's Climate Protection Program ("CPP"), and whether NW Natural should continue expanding its system to serve new customers, including by offering a line extension allowance to new customers. In addition, Ms. Heiting responds to the Coalition's concerns and proposed disallowances regarding lobbying and political activities and dues and membership expenses.

Q. Please provide a high-level summary of the arguments made by CUB and the Coalition to which you will respond.

A. In their testimony, both CUB and the Coalition make wide-ranging arguments that are intended to call into question whether NW Natural can meet the challenge of climate change and comply with the CPP, whether the gas utility model has any place in Oregon's decarbonized energy future, and more immediately, whether and under what terms NW Natural should serve new customers that desire gas service. These parties suggest that the only way to reduce GHG emissions is to electrify building load, and accordingly each proposes significant changes to NW Natural's line extension tariff designed to reduce the allowance provided to new natural gas customers.

CUB witness Mr. Jenks, in particular, details what he believes to be the three major challenges to the natural gas utility business model: (1) the supposed greater efficiency of electric space and water heating and cooking;[1] (2) the challenge of climate change and, in particular, his opinion that NW Natural does not have a reasonable plan to comply with decarbonization mandates, such as Oregon's CPP;[2] and (3) his concern that the increased cost of conventional natural gas, along with the expense of renewable natural gas ("RNG") and increased spending on energy efficiency, will significantly increase the cost of NW Natural's product.[3] Mr. Jenks argues that these challenges will cause, and indeed are causing, NW Natural customers to leave the gas system, which calls into question whether the assumed useful life of a pipe should be 60 years or more,[4] as well as concerns regarding stranded investments.[5] To address these concerns, CUB recommends that the Commission "phase out" the presumption of prudence associated with capital investments to add new customers.[6] CUB also recommends that the Company's line extension allowance be reduced over the next two years and eliminated in 2025.[7]

[1] CUB/100, Jenks/2-3.
[2] CUB/100, Jenks/3-5.
[3] CUB/100, Jenks/5.
[4] CUB/100, Jenks/6.
[5] CUB/100, Jenks/6.
[6] CUB/100, Jenks/14.
[7] CUB/100, Jenks/17.

Coalition witness Nora Apter also challenges the Company's business model, and in particular, the Company's projections of new customer additions over time, on the belief that gas service is detrimental to the environment and that NW Natural's expectations for CPP compliance are unrealistic.[8] On this point, Ms. Apter questions whether NW Natural's plan to supply its customers with RNG is feasible and beneficial.[9] Moreover, Ms. Apter asserts that adding customers to the Company's system increases the risk and cost to ratepayers compared to building electrification, which she claims is cheaper than direct use of gas and "all but inevitable."[10] This particular position dovetails with the testimony of Coalition witness Ed Burgess who makes some of the same points made by Mr. Jenks to support the Coalition's recommendation that NW Natural's line extension allowance be eliminated in this case.[11]

Coalition witness Charity Fain advocates that the Commission adopt policies that promote switching low- and middle-income customers away from gas utility service to electric service.[12] Coalition witness Greer Ryan opposes allowing NW Natural recovery for its participation in the CPP rulemaking, legislative

[8] Coalition/100, Apter/6-7, 17.

[9] Coalition/100, Apter/15-16.

[10] Coalition/100, Apter/7, 9-10, 13, 16-17.

[11] *See* Coalition/200, Burgess/4, 14-21.

[12] Coalition/300, Fain/4.

advocacy, and its engagement with the City of Eugene,[13] as well as recovery of expenses related to dues and memberships.[14]

Q. Please summarize your testimony.

A. CUB's and the Coalition's testimony are filled with broad statements and sweeping conclusions, all of which are grounded in two central beliefs:(1) NW Natural cannot decarbonize its system as required by the CPP; and (2) it is both possible and less expensive for Oregon's electric utilities to serve all new building load, along with their existing load and transportation load, both safely and reliably, with renewable energy. Based on these beliefs, CUB and the Coalition suggest that the only way for Oregon to reach its decarbonization goals will be to electrify building load, while discouraging the addition of new customers to the gas system and ultimately phasing out natural gas service over time. However, these parties' beliefs, and their ultimate conclusions, are unsupported by any persuasive analysis specific to Oregon and NW Natural's service territory, and in fact, are contradicted by initial analyses performed by NW Natural and brought into question by work by third-party experts, Environmental+Energy Economics ("E3"). For these reasons, the Commission should reject CUB's and the Coalition's arguments.

As an initial matter, before the Commission can evaluate the gas utilities' CPP implementation strategies—or any proposals to revise existing line extension policies—it will require significant additional information, as recognized by Staff in

[13] Coalition/400, Ryan/38-41.

[14] Coalition/400, Ryan/5, 42-48.

its Draft Report in the natural gas fact-finding docket, UM 2178 ("Fact-Finding docket"). Specifically, the Commission will require robust data about the natural gas utilities' ability to decarbonize their product. The Commission will also require analyses by the electric utilities regarding the cost and their ability to electrify additional load—both transportation and building load—without compromising reliability and while meeting the transformational requirements recently enacted in House Bill ("HB") 2021. NW Natural has advocated that the Commission sponsor an Oregon-specific, economy-wide decarbonization study that includes the gas, electric, and transportation sectors and explicitly models the capacity needed to maintain reliable service during extreme weather events when service interruptions are most dangerous to Oregonians. At present, there has been only one in-depth analysis as to the most efficient and cost-effective approach to decarbonizing the energy sector in Oregon while meeting peak heating loads; that study concludes that natural gas companies can continue serving existing and new customers and that this approach is likely less expensive for Oregonians than building electrification, particularly considering the types of electric heat pumps that are being installed in Oregon today. While this comprehensive study, like other deep decarbonization studies conducted in the Northwest, was completed before the CPP rules were enacted and HB 2021 was passed, and therefore may not be definitive on all relevant issues, it suggests that CUB's and the Coalition's rush to judgment on the future of natural gas is misguided and that rapid, wholesale electrification of building load is neither economical nor necessary for meeting Oregon's decarbonization targets.

Importantly, NW Natural's initial analysis performed in docket UM 2178 indicates that the Company can continue serving customers and responsibly grow its system, while also complying with the specific requirements of the CPP—contrary to CUB's and the Coalition's testimony. In fact, the UM 2178analysis shows that customers will be better off under the Company's proposed compliance scenarios than under a scenario that discourages or outright limits the Company's growth. Although the Company's CPP-compliance modeling is preliminary, and more robust modeling using more appropriate analytical tools is currently underway in NW Natural's integrated resource plan ("IRP"), the Company is confident that it can comply through a combination of energy efficiency and renewable gas (RNG, hydrogen, and synthetic gas) under a wide range of potential future market and policy conditions. Given the potential technical challenges and cost impacts of an "electrify everything" approach, these new and emerging renewable gas supplies may well be critical to Oregon's ability to maintain reliable energy while meeting climate goals. In fact, the Oregon legislature and Governor Brown have both specifically recognized the vital role RNG can play in helping Oregon meet its climate goals.[15] It is for precisely this reason that in its Draft Fact-Finding Report issued in docket UM 2178, Staff encouraged the gas utilities to continue to pursue RNG, hydrogen gas, and any new or emerging technologies to preserve maximum optionality for decarbonization.

[15] *See* Office of the Governor State of Oregon, Executive Order No. 20-04; S.B. 98, 80th Leg. Assemby, Reg. Sess. (Or. 2019).

Moreover, the Commission should reject outright CUB's claim that customers are already leaving the natural gas system in substantial numbers or are poised to do so,[16] as well as the Coalition's claim that Oregonians are broadly rejecting natural gas service.[17] CUB and the Coalition make these claims to argue that the gas utility model is failing and therefore any expansion of the gas system is certain to result in stranded costs.[18] These arguments, however, rest on a fallacy. As we demonstrate below, the actual data do not show an increasing trend in customers converting gas equipment to another fuel source or leaving the natural gas system. In fact, in making these arguments, the Coalition and CUB are not shining a light on a problem that already exists, but rather are striking a match to create one—by proposing line extension policies that will discourage customers from connecting to the gas system. The Commission should decline this invitation to drive a market result that is not "inevitable" or supported by Oregon legislative or regulatory policy.

On this point, NW Natural urges the Commission to consider the unintended consequences of a significant reduction in the Company's line extension allowance in this case. Even if the Commission were to take such an action on an interim basis,[19] while it gathers further information on GHG reductions, such a

[16] CUB/100, Jenks/3, 6-7.

[17] Coalition/100, Apter/11-14.

[18] *See* CUB/100, Jenks/6-7, 13; Coalition/200, Burgess/17; Coalition/300, Fain/23.

[19] *See In re Oregon Public Utility Commission Staff Natural Gas Fact Finding per Executive Order 20-04 PUC Year One Work Plan*, Docket UM 2178, Staff's Draft Report at 24 (Apr. 15, 2022) (identifying exploration of "interim, easily implemented approach to line extension allowance policy" as near-term action).

determination could signal that it has pre-decided a diminished role for gas utilities in Oregon's energy future, which in turn could impair the Company's financial health and its ability to access the resources necessary to pursue all available strategies for decarbonization. Presupposing NW Natural's system is not necessary or socially beneficial to realizing Oregon's clean energy future would be irresponsible in the absence of supporting, Oregon-specific analysis. In fact, making this kind of far-reaching policy change without a comprehensive assessment of energy system risks and costs would very likely, and unnecessarily, interfere with the state's ability to achieve its climate goals.

Finally, and perhaps most importantly, the Commission should reject the subtext underlying CUB's and the Coalition's proposals—the belief that it is the Commission's role to determine Oregon's path to decarbonization, and that the Commission possesses the authority to "choose" electrification over a route that allows natural gas utilities to demonstrate compliance with emissions reduction requirements. In fact, the policies proposed by CUB and the Coalition are far outside the scope of the Commission's jurisdiction, which is to oversee the utilities' compliance with *current* state decarbonization laws, as articulated by the legislature and the direction provided by Executive Order ("EO") 20-04. As discussed further below, those laws and policies are focused on emissions reductions, not fuel-switching, and they explicitly encourage the transition of gas utilities to RNG.

Q. Do you include any exhibits with your testimony?

A. Yes, our testimony includes the following exhibits:

- NW Natural/1701, Heiting-Bracken is an Oregonian article regarding electric utilities' challenges to decarbonize.
- NW Natural/1702, Heiting-Bracken is the Pacific Northwest Pathways to 2050 study conducted by Energy+Environmental Economics.
- NW Natura/1703, Heiting-Bracken is Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience.
- NW Natural/1704, Heiting-Bracken is the presentation of NW Natural's modeling results in the Fact-Finding, docket UM 2178.
- NW Natural/1705, Heiting-Bracken is a presentation by Enbridge regarding natural gas heat pumps.
- NW Natura/1706, Heiting-Bracken is the confidential ANSI/ASHRAE's Standard Methods of Determining, Expressing, and Comparing Building Energy Performance and Greenhouse Gas Emissions.
- NW Natural/1707, Heiting-Bracken is NW Natural's comparison of the efficiency of gas and electric heat pumps.
- NW Natural/1708, Heiting-Bracken is the American Gas Association, Review and Comments "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Home," Environmental Science & Technology, 2022.

- NW Natural/1709, Heiting-Bracken is Issues that Render the Sierra Club/UCLA Study of *Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California* Not Useful for Decision-Making Purposes.
- NW Natural/1710, Heiting-Bracken is the Company's confidential response to UG 435 Coalition DR 158.
- NW Natural/1711, Heiting-Bracken is the Company's response to UG 435 Coalition DR 73.

II. RESPONSE TO PARTIES' ARGUMENTS

A. The Commission should not significantly alter the policies governing NW Natural's customer-acquisition framework in this rate case.

Q. Please explain why, in the Company's view, the Commission should not entertain the parties' proposals to reduce and eliminate NW Natural's line extension allowance in this rate case.

A. First, as context, we point out that NW Natural's current line extension policy has been in place for nearly a decade, and during that time, it has allowed new customers to obtain gas service while fairly and equitably recognizing the upfront costs to serve new customers, the margin revenues produced by the new customers, and the benefits that accrue to all customers when new costs are spread across an expanded base. The reasonableness of this line extension policy is detailed in the Reply Testimony of John Taylor of Atrium Consulting, NW Natural/1800, Taylor.

At NW Natural, we recognize the challenge of climate change that requires us to reevaluate all aspects of our retail energy markets, including the best approaches to reduce GHG emissions in the electric, gas, and transportation sectors. And we certainly acknowledge that it is fair for the State's policy makers to explore whether an expanded gas system is beneficial to customers and consistent with the State's climate goals, just as it is fair to ask whether the State can safely rely on electricity alone to heat our buildings while the electric utilities comply with HB 2021. In fact, these are pressing questions that must be addressed. However, the determination of the best path toward decarbonization is outside the scope of the Commission's authority, which is to assure utilities' compliance with current state laws and policies.

Moreover, to the extent that the Commission is considering whether the Company's line extension tariff does comply with current laws and policies, that issue can only be responsibly debated in the context of facts and sound Oregon-specific analysis, as opposed to presupposition, bias and rhetoric. As such, it is critical that the Commission refrain from making significant changes to the Company's line-extension policy until it has gathered the relevant data and analysis. In this context, the Commission and the parties have more work to do. Specifically, the Commission should (1) allow the electric and gas utilities to complete their IRP processes in which they will present their detailed, fully analyzed plans for complying with the CPP, HB 2021, and other important policies; and (2) commission an Oregon-specific comprehensive analysis of the feasibility and cost of all available paths to decarbonizing the retail energy sector, including electric, gas, and transportation that explicitly and deliberately considers reliability during extreme weather events.[20]

Q. You testified that the Commission needs additional information and analysis to understand how gas and electric utilities can comply with decarbonization mandates and at what cost to customers. Will the necessary information be developed in the ongoing Fact-Finding docket, or is additional analysis necessary?

A. It is crucial that the Commission consider additional analysis beyond what has been developed in the Fact-Finding docket to-date, which is necessarily preliminary in nature and higher level, given the posture and timeline of that docket. As Staff's Draft Report explained,

> The uncertainty in costs, performance risks, and availability of resource options for each pathway to decarbonize has raised ***many more questions to be addressed to ensure the planning and decision-making process supports the identification of the least-cost and least-risk approaches to future GHG emission compliance***. While the gas companies, stakeholders, policy makers, and regulators must chart a pathway to meet the CPP requirements, ***technology costs and performance remain highly speculative***. The analysis from the [Fact-Finding docket], while informative, made it clear that ***more robust modeling and rigorous vetting of resource assumptions within Integrated Resource Plans (IRPs) will be required to make informed assessments about least cost, least risk paths for compliance***.[21]

[20] NW Natural also notes that decisions about the future of natural gas in Oregon should likely occur in a proceeding that involves the other Oregon natural gas utilities, rather than in a single utility's rate case. The Coalition appears to agree that a generic investigation is an appropriate approach for setting policy regarding line extension allowances. Coalition/200, Burgess/30 (recommending investigation into line extension allowance for all gas utilities).

[21] Docket UM 2178, Staff's Draft Report at 9 (emphasis added).

Q. Can you expand upon the type of additional information the Commission needs to consider?

A. Yes. First, arguments that the Commission either should or should not adopt policies that will drive electrification of building loads must be addressed by current legislative direction. As noted above, building electrification is not the law in this state, and even if the Commission wished to consider that policy, it lacks authority to do so. Moreover, to the extent the Commission determines it must wade into this debate in the context of the parties' line extension proposals, it cannot make an informed decision regarding the necessity and impacts of altering NW Natural's line extension policy without understanding the ability of the electric system to reliably serve with clean energy the significant new loads that will result from electrification of buildings along with transportation electrification. This work has yet to be done at a utility-specific level where new annual and peak loads are modeled to be served on an hourly basis as part of a robust electric resource planning process.[22] As Staff notes, robust modeling through utilities' IRPs will provide insight regarding the utility's least-cost, least-risk paths for compliance,[23]

[22] PacifiCorp's recently filed IRP does not include analysis to understand what is required to meet HB 2021, and PGE's most recently filed IRP update forecasts increasing emissions to around 2030 rather than the 80 percent reduction by 2030, now required by HB 2021. Therefore, PGE's next IRP, which will be filed in 2023, must have drastic changes.

[23] Docket UM 2178, Staff's Draft Report at 9.

and additional information regarding the interactions between the gas and electric systems is needed.[24]

To enable the necessary coordination, Staff recommends that the Commission request that both gas and electric utilities develop and articulate individual electrification assumptions in future IRPs that others can reference.[25] NW Natural agrees that it is critical that the utilities include this information in their IRPs. In addition, NW Natural recommends that the Commission undertake an analysis that comprehensively examines Oregon's electric and gas systems to understand how electrification impacts each system's cost, reliability, and ability to decarbonize in the context of compliance with the CPP and HB 2021.

NW Natural acknowledges Staff's statements in the Fact-Finding docket Draft Report about the difficulties of conducting an analysis regarding the interactions between the gas and electric systems,[26] and the additional resources that would be required.[27] Because these issues are absolutely critical for our State and region, however, the Commission should at a minimum insist upon robust and coordinated IRP planning processes prior to making any significant changes to NW Natural's line extension policy.

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[24] Docket UM 2178, Staff's Draft Report at 9 ("Oregon's carbon reduction goals cement the interrelatedness of gas and electric operations decisions more than ever before.); *Id.*at 28 (explaining the "need to understand the interdependency of the gas and electric systems in terms of costs and emissions that result from policies that shift load away from gas").

[25] Docket UM 2178, Staff's Draft Report at 23.

[26] Docket UM 2178, Staff's Draft Report at 15.

[27] Docket UM 2178, Staff's Draft Report at 2, 7, 23.

B. Parties incorrectly assume that all building load can and must be electrified.

Q. Testimony from the Coalition, and to a somewhat lesser extent CUB, regarding the role of gas in a low-carbon future is premised upon the assumption that all or most building load can and should be electrified to meet Oregon's climate goals. Do CUB and the Coalition support their arguments with any persuasive analysis?

A. No. The CUB and Coalition proposals rest on the unstated belief that the electric utilities in Oregon can serve all new (and over time much of the existing) building load and do so with fewer emissions and at a lower cost than gas. Notably, however, both CUB and the Coalition rely on high-level talking points that are unsupported by comprehensive, state-specific, objective, data-driven analysis and citations to analysis for other jurisdictions that are not fully applicable to Oregon's climate or existing energy system.

Q. Is there any Oregon law or policy requiring, or even encouraging, the electrification of gas load?

A. No, and in fact, Oregon law and policy recognize and support the ongoing role of RNG in Oregon's energy transition. Specifically, in Senate Bill ("SB") 98, which was passed in 2019 and authorizes Oregon natural gas utilities to procure RNG, the Oregon legislature found that RNG "provides benefits to natural gas utility customers and to the public" and that RNG development "should be encouraged to support a smooth transition to a low carbon energy economy in Oregon."[28] The legislature further declared that "[n]atural gas utilities can reduce emissions from the direct use of natural gas by procuring [RNG] and investing in [RNG] infrastructure," and that RNG "should be included in the broader set of low carbon resources that may leverage the natural gas system to reduce [GHG] emissions."[29]

In addition, EO 20-04, which establishes GHG reduction targets, states that "transitioning the traditional natural gas supply to [RNG] can significantly reduce GHG emissions."[30] Notably, while EO 20-04 specifically discussed *transportation* electrification, it does not promote or even mention *building* electrification.[31] Finally, the CPP itself recognizes that RNG can be used in lieu of conventional natural gas to lower emissions and help Oregon's natural gas utilities comply with the program.[32]

Q. Does NW Natural agree with the premise that building electrification is the only or best way to achieve Oregon's climate goals?

A. No. NW Natural strongly disagrees with this premise for several reasons. First, currently, electric heating in Oregon is often more carbon-intensive than gas heating given the relative emissions intensity of the electric sector in Oregon and particularly given the ongoing widespread use of electric resistance heating in

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28 ORS 757.390(1).

29 ORS 757.390(2).

30 Office of the Governor State of Oregon, Executive Order No. 20-04.

31 *See, e.g.*, Executive Order 20-04, Section 5(B)(2) (directing Public Utility Commission to encourage transportation electrification).

32 *See* OAR 340-271-0110(4)(b)(B)(i).

existing homes and new construction. Second, there are significant questions regarding the electric utilities' ability to electrify building load—and potentially transportation load—while at the same time decarbonizing their generation portfolios as required by HB 2021. And third, even if the electric utilities are able to decarbonize while rapidly electrifying building and transportation load, it is in no way clear that they could decarbonize more economically than the gas system.

Q. Please elaborate on your first statement—that currently, electric heating in Oregon is often more carbon-intensive than gas heating.

A. At present, given market trends and relative emissions intensities, electrifying heating load in Oregon will not result in decreased emissions, depending on the customer's equipment and utility provider. While the electric system is working to decarbonize and must comply with HB 2021, and while it is critical that we plan for the long-term, near-term emissions reductions provide significant long-term climate benefits. To this point, the current GHG intensity of Oregon's electricity and, specifically, the electric heating equipment that continues to be installed, needs to be carefully considered.

At present, electrification of gas heating load using electric resistance heating would result in substantial emissions increases for nearly all gas utility customers in the state. Replacement of gas heating with the electric heat pumps most commonly installed today would not result in meaningful emissions reduction in the near-term, and, depending on the electric provider, would result in substantial emissions increases for a large share of Oregonians who are current or prospective gas utility customers.

There is very little emissions benefit to the state from electrification of gas heating (currently and in the years to come) when accounting for areas of the state where gas utilities and electric utilities have overlapping service territories, and weighing the emissions trajectories of heating with gas and electricity in the context of the CPP and HB 2021. Furthermore, if all gas heating in the state were replaced with the most commonly installed electric heat pumps tomorrow, it would reduce emissions in the state by roughly one percent with the current emissions intensity of electricity in Oregon where gas service is available. Given the prevalence of electric heating in Oregon, and that space-heating loads are most prevalent when the electric grid is more emissions intensive than the annual average, it is possible that it may not reduce emissions at all. The figure below shows (i) current Oregon emissions, (ii) the total portion that results from direct use of natural gas, (iii) the portion that results from direct use of natural gas by residential and commercial customers, (iv) the portion that results from direct use of natural gas for space heating, and (v) the portion that would be reduced if all direct use space heating were electrified with high efficiency heat pumps today.

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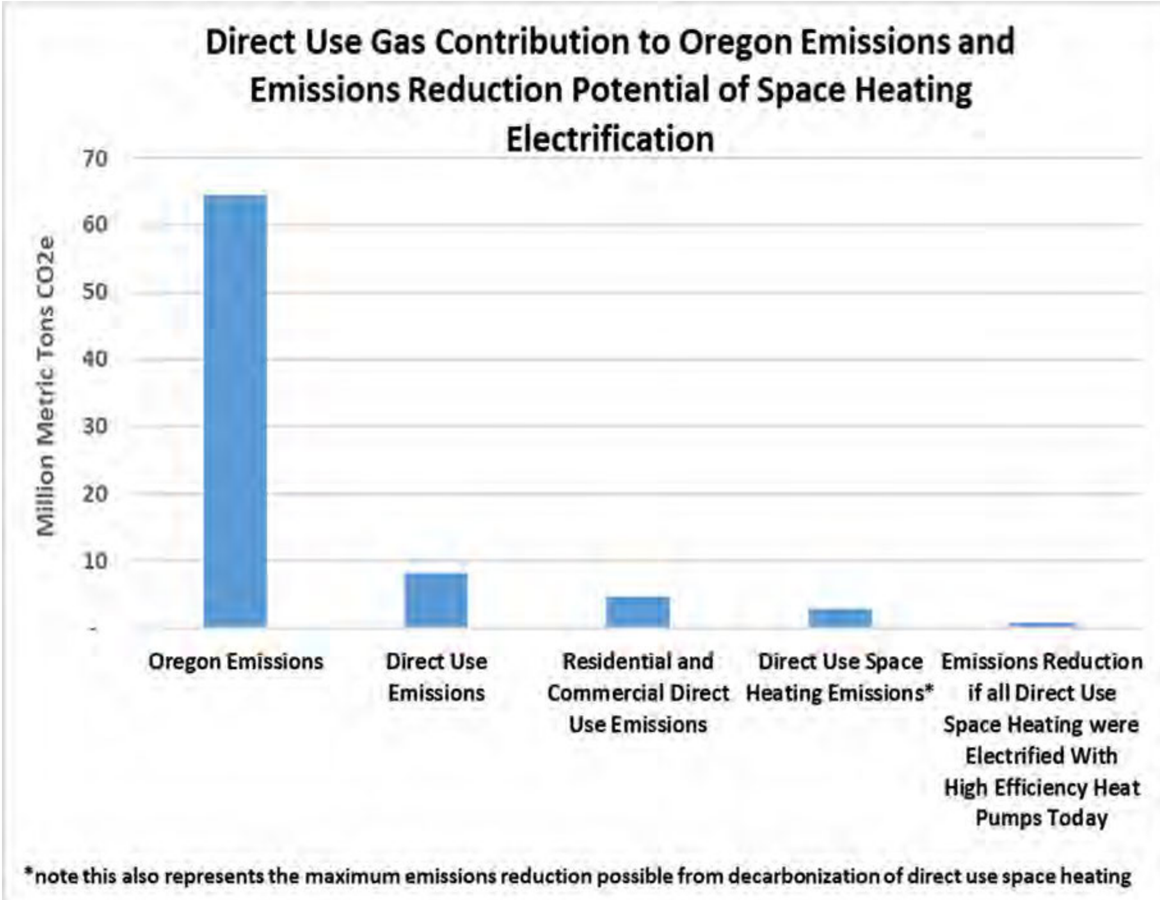
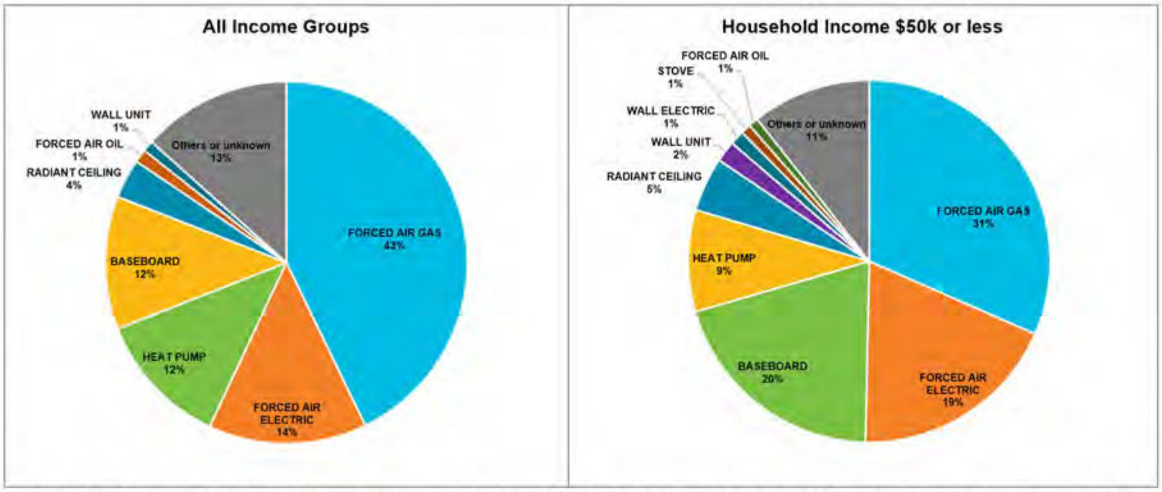


Comparatively, if electric resistance heat currently serving households in Oregon could instantly be transitioned to gas furnaces or electric heat pumps, the associated GHG emissions attributed to heating for those customers would be reduced by at least half, and these customers would also pay less than half of what they currently pay to heat their homes. Currently, inefficient resistance electric heating equipment, not heat pump technology, makes up the largest share of electric heating in NW Natural's service territory, as shown in the figure below.



About half of low-income households are using the costliest, least comfortable and highest emitting electric resistance heat.

Source: Corelogic/Espolin – 2021, NW Natural Service Territory; Includes Single Family and Multifamily Housing

Q. Please explain your second point—that there are questions regarding the electric utilities' ability to rapidly and completely decarbonize their existing load while also serving the significant increase in load that would result from electrifying transportation and buildings.

A. Under HB 2021, Oregon's electric utilities must dramatically reduce their emissions. As recently as last year, spokespersons for PacifiCorp and Portland General Electric Company ("PGE") acknowledged that the electric utilities do not currently have a plan to achieve 100 percent emissions reductions by 2040.[33] In fact, both PacifiCorp and PGE have acknowledged that achievement of these reductions will require advancements in technology—such as storage—and construction of massive amounts of generation and transmission on an expedited timeframe. We note that HB 2021 includes a "reliability pause" that allows

[33] *See* NW Natural/1701, Heiting-Bracken.

regulators to temporarily exempt the electric utilities from meeting the bill's targets if necessary to maintain reliability.[34]

In making this point we are not critical of the electric utilities. Like the gas utilities, they have been charged with a monumental task—to rapidly decarbonize their service without sacrificing reliability and to do so at a reasonable cost. So, it makes perfect sense that they do not yet know exactly how they will meet this challenge. We are pointing this out only to emphasize that in this respect, the gas and electric utilities are similarly situated.

Q. Please explain your third point—that it is not clear that a decarbonized electric system can more economically serve electrified building load.

A. Assuming Oregon's electric sector will be able to meet the obligations in HB 2021, significant questions remain regarding the electric system's ability to reliably serve the increase in load that would result from building electrification at a cost that is lower than or comparable to decarbonization of the direct use gas system. To date, there has been no state-sponsored,[35] Oregon-specific study or other detailed analysis that fully evaluates the feasibility and cost of electrifying transportation *and* buildings, the impacts of electrification on the reliability of the electric grid, the costs of electrifying everything that will be paid for by electric customers, and the emissions under different electrification scenarios in comparison to direct

[34] H.B. 2021, 81st Leg. Assemb., Reg. Sess. at 6-7 (Or. 2021).

[35] NW Natural supports a state-sponsored study because such a study would best ensure participation and buy-in. State sponsorship is likely the best way to ensure all industry and utility actors are required to produce the necessary information and that the study results are accepted as credible by all interested parties.

decarbonization of gas utility load. Accordingly, racing ahead to electrify new construction in Oregon—which is what it appears the Coalition and CUB are seeking to accomplish with their proposed changes to NW Natural's line extension policy—without understanding these dynamics is not a responsible or effective plan. Indeed, Staff recognized these concerns in the Fact-Finding docket Draft Report, noting the potential for electrification to shift cost and risk onto electric ratepayers,[36] and impact electric utilities' winter reliability and ability to comply with the aggressive decarbonization requirements in HB 2021.[37] Moreover, the most comprehensive Oregon-specific analysis conducted to-date to study the role of buildings in economy-wide decarbonization shows that electrifying building load could prove to be a high-cost route to achieving the state's climate goals, and that continued direct gas use is a viable option for decarbonizing building loads.

Q. Please explain the Oregon-specific analysis regarding the ability of both natural gas and electric utilities to reduce GHG emissions in Oregon while reliably serving winter peak heating loads.

A. In 2018, NW Natural contracted with E3 to perform an independent analysis evaluating the technology implications and potential costs of different strategies to achieve 80 percent reduction of GHG emissions in Oregon and Washington below 1990 levels by 2050 ("E3's Oregon Study").[38]

[36] Docket UM 2178, Staff's Draft Report at 16.

[37] Docket UM 2178, Staff's Draft Report at 23.

[38] *See* NW Natural/1702, Heiting-Bracken (E3 analyzed Washington and Oregon separately, and our testimony discusses the Oregon-specific information, so we refer to the study as "E3's Oregon Study").

E3's Oregon Study focused on the role of buildings with special attention to building space heating during periods of cold temperature when the electric and gas systems concurrently experience peak demand.[39] E3's analysis considered what would be required of the winter-peaking electric system if it were to also be responsible for the gas system's "substantial "winter peak heating needs."[40] E3 specifically evaluated four scenarios:

(1) maintaining gas use in buildings and primarily using gas furnaces to provide heat, the "Gas Furnace Scenario";

(2) maintaining gas use in buildings and primarily using natural gas heat pumps to provide heat, the "Gas Heat Pump Scenario";

(3) transitioning and retrofitting buildings currently using natural gas for heating to use electric heat pumps that are more efficient than required under current building codes, the "Electric Heat Pump Scenario"; and

(4) transitioning and retrofitting buildings to use cold-climate electric heat pumps ("CCHP"), the "Cold Climate Heat Pump Scenario."[41]

Like comparable deep decarbonization studies, E3's Oregon Study assumes that all current electric resistance heating is replaced with ductless electric heat pump systems in all scenarios.[42] The electric-heat-pump scenario relies on electric heat pumps that are more efficient than the average systems

[39] *Id.* at 17. E3 explained that a "key take-away from the existing literature on decarbonizing heat, both in and outside the Northwest, is the importance of accounting for peak conditions." *Id.* at 35.

[40] *Id.* at 35.

[41] *Id.* at 19.

[42] *Id.* at 51.

being installed today,[43] and the CCHP scenario relies on CCHPs, which are more efficient and perform better under cold weather conditions but make up only a small share of heat pumps currently being installed in the Pacific Northwest.

Q. What did E3's Oregon Study conclude?

A. E3 concluded that maintaining gas heat in buildings is a feasible strategy to achieve 80 percent GHG reduction by 2050,[44] and stated: "This study suggests that continued use of the natural gas distribution system is a cost-effective strategy to meet the region's climate goals while also reliably serving winter peak demands."[45] When assessing electrification of space heating, E3's projected costs to the Oregon economy show that using non-CCHP electric heat pumps is the most expensive strategy for decarbonizing the State's energy needs.[46] E3 explained, "some electrification measures are more cost effective than others, so like other emission reduction opportunities, *electrification must be used strategically*. An important consideration when evaluating the costs of electrification are the potential impacts to the electric system's peak demand and associated infrastructure costs."[47]

[43] *Id.* at 74 (assumed standard heat pumps in the study are HSPF of 9.2 systems, which is more efficient than current code and is more efficient than typical system installed in the Pacific Northwest today).

[44] *Id.* at 95-97.

[45] *Id.* at 100.

[46] Importantly, electrification of space heating using non-CCP heat pumps is precisely the result that would be accomplished if we were to move forward with an electrification policy in the current Pacific Northwest heating market.

[47] NW Natural/1702, Heiting-Bracken/31 (emphasis added).

It is important to note that E3's Oregon Study was completed before the passage of HB 2021 and does not require electricity to be 100 percent carbon free (though in all scenarios the electric generation is more than 95 percent emissions free in 2050), nor does the study prohibit the construction of new natural gas power generation. To keep costs as low as is shown in E3's results would require large-scale new development of natural gas peaking plants to provide the firm service needed to serve peak needs, which is unlikely following HB 2021.

Q. How do the projected costs of E3's four scenarios compare?

A. The figures below compare the costs over time of the four scenarios E3 analyzed. The first figure, from E3's Oregon Study, shows the incremental costs to Oregon's economy of each scenario to meet the same emissions reduction goal,[48] and the second figure compiles the individual results into one graph for ease of comparison.[49]

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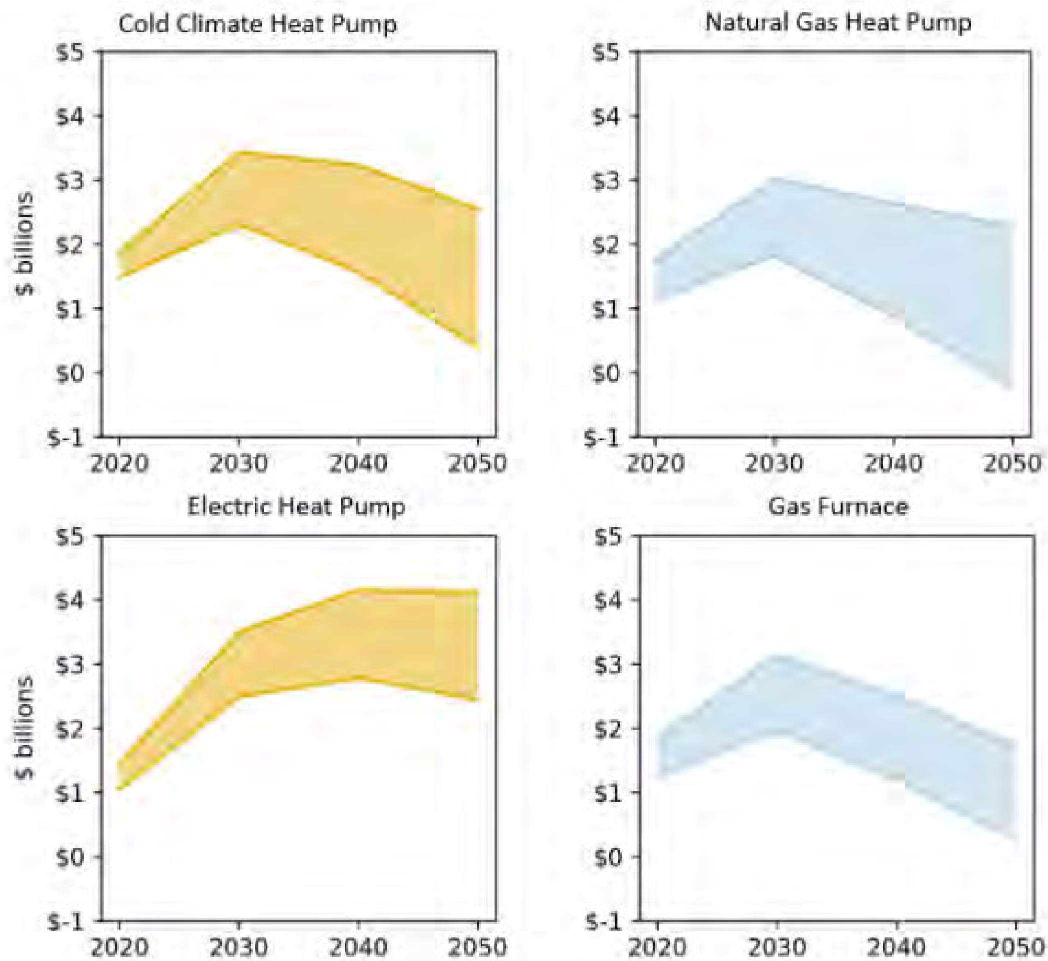
[48] *Id.* at 121. Scenario costs shown are for Oregon only and represent incremental cost to the Oregon economy for meeting the state's emissions goals. Scenarios all have the same emissions profile through time and are meant to be compared based on cost.

[49] The results of the two heating electrification scenarios are shown as one range (in blue) and the results of the two gas heating scenarios are shown as one range (in green). The mid-point of each range is shown with a hashed line.


Cold Climate Heat Pump
Natural Gas Heat Pump
Electric Heat Pump
Gas Furnace
$ billions
$5
$4
$3
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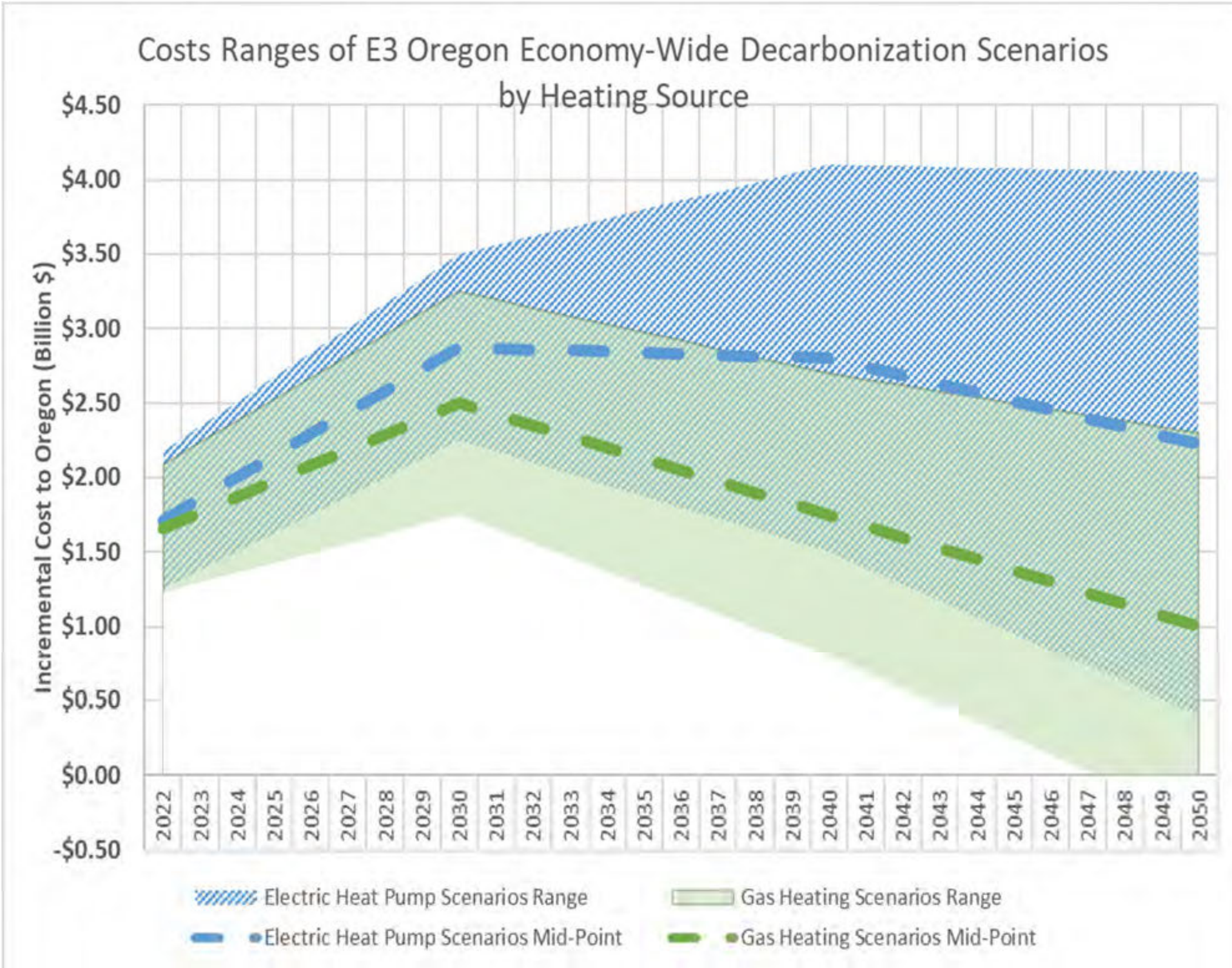

E3's Oregon Study is the most comprehensive state-wide decarbonization analysis performed to date that focuses on reliably serving building loads under deep decarbonization, and it concludes that using the gas system for space heating is a feasible method of meeting the state's climate goals. These findings contradict the Coalition's and CUB's assertions that the state must move rapidly toward building electrification to meet its climate goals in a cost-effective way.

Q. Please describe the challenges E3 identified for achieving 80 percent GHG reductions under each scenario.

A. E3 concluded that all scenarios will require technological innovation,[50] and that it is likely that near-complete electrification of the transportation sector,[51] which is the largest source of GHG emissions in Oregon and Washington, would be beneficial.[52] All scenarios also rely upon carbon-neutral biofuels displacing gaseous fuels.[53] For the scenarios that rely upon natural gas remaining the primary source for heating needs, continued research, development, and investment would be needed to bring significant amounts of carbon-neutral fuels such as RNG to market.[54] The electrification scenarios would require transforming the HVAC and water heater market and rapid consumer acceptance and conversion to electric appliances.[55] In addition, the non-CCHP-electrification scenario was by far the highest cost of the scenarios "based on the relatively poor performance of the conventional heat pumps in cold weather,"[56] and E3 opined that "from a grid perspective," consumers should install the more expensive cold-

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[50] NW Natural/1702, Heiting-Bracken/96.

[51] *Id.* at 99.

[52] *Id.* at 29.

[53] *Id.* at 99.

[54] *Id.* at 96-97. NW Natural notes that much of this research, investment, and development is now underway since the study was completed, as discussed below.

[55] *Id.* at 97.

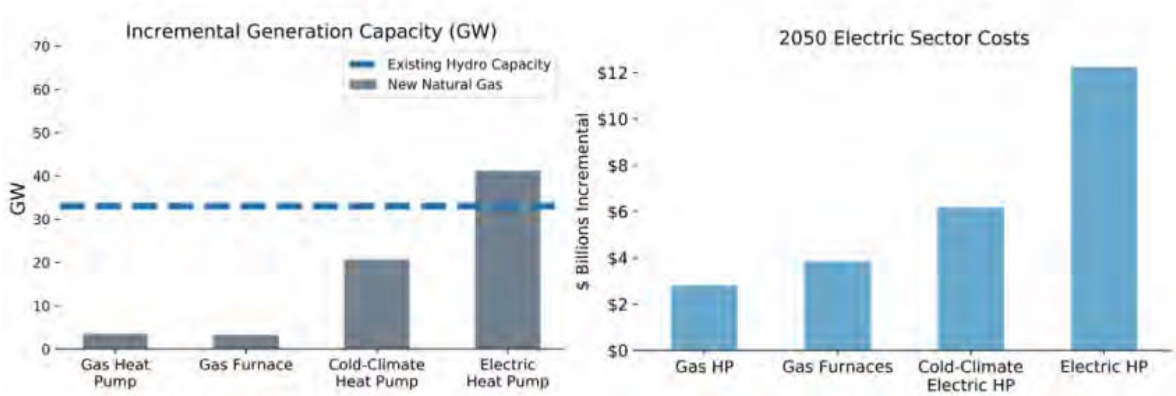
[56] *Id.* at 88.

climate heat pumps "to avoid the highest system-wide cost impacts to the electric grid."[57]

Q. Did E3 evaluate reliability impacts of the electrification scenarios?

A. Yes, the study focused on the cost of the electric system to reliably meet peak heating load under scenarios where the majority of space heating continues to be served by gaseous fuels in comparison to scenarios that employ full building electrification. E3 noted that wholesale building electrification would add new weather-dependent electric loads that would drive the need to install ***20,000 to 40,000 MW*** of new electric generation capacity by 2050 to maintain reliable service during cold weather events, which would also require significant investment in new transmission and distribution infrastructure.[58] For comparison, the entire hydroelectric system in the Pacific Northwest represents 33,000 MW of installed capacity, as shown by the dotted line in the figure below.[59]

Figure 29. 2050 incremental firm capacity build by scenario and 2050 electricity sector cost by scenario



[57] *Id.* at 97.

[58] *Id.* at 97-98.

[59] *Id.* at 84.

Q. The Coalition references several studies in their testimony: (1) an E3 study that concluded building electrification leads to lower energy bills in California ("E3's California Study");[60] (2) a Washington study that found electricity is the cheapest option to decarbonize buildings in Washington State;[61] and (3) a Rocky Mountain Institute report finding that all-electric homes in Seattle are cheaper than those that use gas.[62] Why are these studies less applicable to Oregon than the E3 Oregon Study ?

A. To be clear, the studies referenced by the Coalition were conducted for other places, like California and Washington. There are meaningful differences between Oregon and both California and Washington that the Coalition failed to account for in their testimony, which render the studies they referenced inapt. Specifically, Oregon's electric sector is far more emissions intensive than Washington's or California's, particularly where the electric and gas systems overlap, as shown in the figure below.[63]

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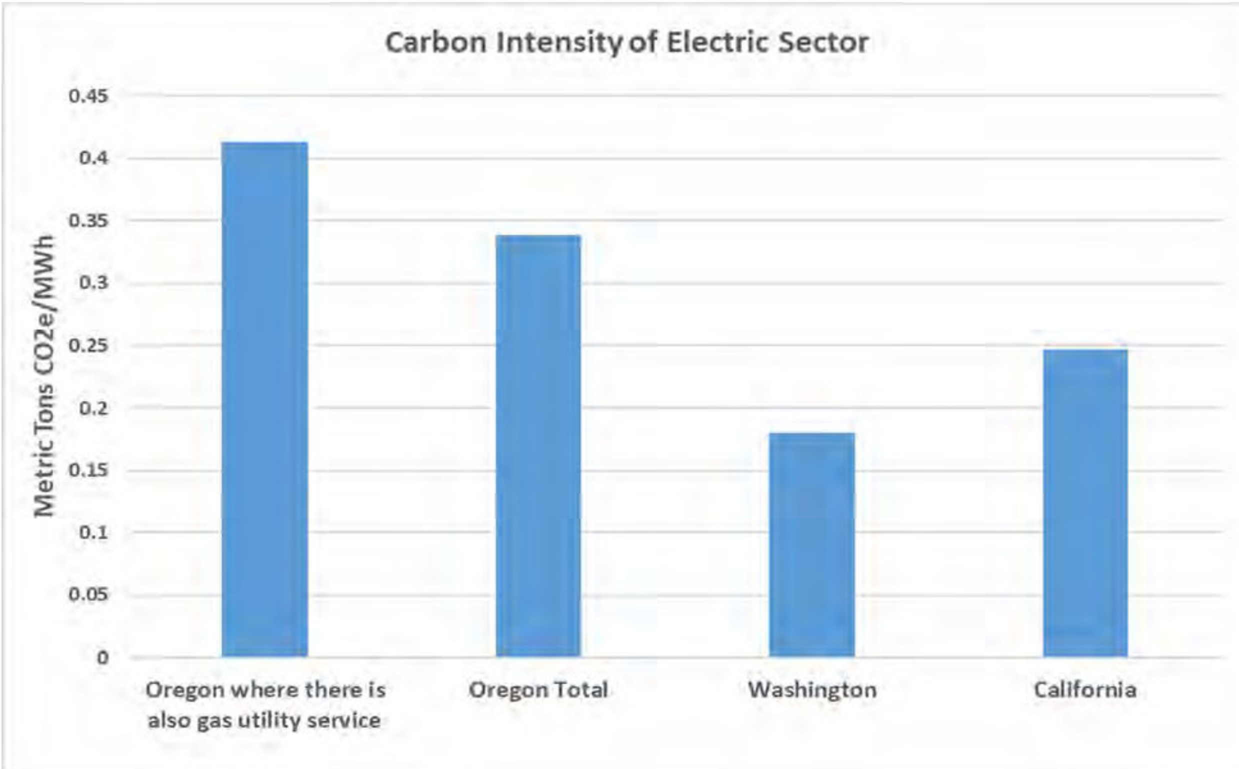
[60] Coalition/100, Apter/16-17.

[61] Coalition/100, Apter/17.

[62] Coalition/200, Burgess/20.

[63] Electric sector emissions in the figure above come from the most recent year of data available from the official greenhouse gas inventories in Oregon (Oregon Department of Environmental Quality ("ODEQ")), Washington (Washington Department of Ecology), and California (California Air and Resource Board). Oregon electric deliveries are also sourced from ODEQ, while California and Washington electric sector deliveries are sourced from the U.S. Energy Information Administration. Per NW Natural's analysis, a weighting of 61 percent for PGE, 27 percent for PacifiCorp, and 12 percent for the average of public power in Oregon were applied to the emissions intensities of these utilities from data reported to ODEQ from the respective utilities.



We will briefly respond to each of the Coalition's referenced studies:

First, the E3 California Study referenced by the Coalition as justification for moving forward with building electrification was prepared for the California Energy Commission, analyzed California's buildings, and specifically directed readers to take care in applying its conclusions outside of California: "This study finds that electrification in buildings is likely to be the lowest-cost means of dramatically reducing GHG emissions *from California's buildings*. However, *this finding is influenced, in part, by California's relatively mild winter climate*."[64] The study also discusses the reduced efficiency of electric heat pumps in colder temperatures,

[64] E3, *The Challenge of Retail Gas in California's Low-Carbon Future* at 15 (Apr. 2020) (available at: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf) [hereinafter California E3 Study] (emphasis added).

the challenges of meeting peak heating needs in colder climates with renewable electricity, and the "ongoing role for low-carbon gas as a 'peak-heat' capacity resource" in colder climates—specifically citing E3's Oregon Study.[65] Thus, the California E3 Study is consistent with E3's findings in the Oregon-specific study we discussed—and inconsistent with the Coalition's advocacy that Oregon's buildings should be electrified to meet the State's climate goals.

The second study the Coalition references was conducted by Washington State.[66] As shown above, Oregon's electric sector is twice as emissions intensive as Washington's, and 2.5 times as emissions intensive where there is gas utility service in the state, meaning that Washington's power generation currently contributes much less to the state's emissions than Oregon's power generation does. Correspondingly, only 16 percent of Washington's emissions come from electricity,[67] versus 29 percent for Oregon.[68] While these percentages may vary from year-to-year based on hydro conditions and weather, Washington's electric

[65] California E3 Study at 15 ("Electric heat pumps are an efficient means to deliver heating and cooling, but the associated efficiency decreases as the outdoor air temperature drops. Electric resistance heating is commonly used as a supplemental heat source in cold climates, but this use can also lead to substantial new electric-peak demands and the needs for new electric infrastructure in colder climates. Cold climate heat pumps are making important technology strides, but 'peak-heat' challenges have been identified as legitimate concerns in colder climates, including parts of northern Europe (Strbac, 2018) and the northern United States (Aas, 2018). Peak heat needs occur during the coldest periods of the year when demand for heating in buildings in highest. These cold periods become particularly challenging when they correspond to periods of low renewable electricity availability. ***Research in those colder jurisdictions tends to find a plausible ongoing role for low-carbon gas as a 'peak-heat' capacity resource***." (emphasis added) (citing NW Natural/1702, Heiting-Bracken)).

[66] *See Washington State 2021 Energy Strategy-First Draft* (Nov. 2020) (available at: https://www.commerce.wa.gov/wp-content/uploads/2020/11/WA-2021-State-Energy-Strategy-FIRST-DRAFT-2.pdf) [hereinafter *Washington Energy Strategy*].

[67] Washington Energy Strategy at 7.

[68] Docket UM 2178, NW Natural's Comments at 3 (July 2, 2021).

system currently is much cleaner than Oregon's. This results in two important differences when comparing building electrification in Washington and Oregon: (1) electrification of direct use natural gas loads in Oregon results in far less emissions reduction (and in many cases results in increased emissions) in the near term, and (2) with or without building electrification, the cost to decarbonize the electric grid in Oregon will be more expensive per unit of delivered electricity than in Washington because more decarbonization is required. It is worth noting however, that even though Washington's electric generation is comparatively clean, the study's electrification scenario still found that the state would need to import 43 percent of its power by 2050—mostly from Montana and Wyoming wind.[69] To accomplish this, the study assumes "*[s]ix GW* of new transmission (the maximum permitted in the model) are added between Montana and Washington *and 5 GW* between Idaho and Washington by 2050."[70] Permitting and constructing such a massive amount of new transmission capacity would be extremely challenging on the timeline assumed—if not impossible—calling into question the validity of the study's conclusion that building electrification is the cheapest way to decarbonize

[69] Washington Energy Strategy at 25.

[70] *Washington Energy Strategy* at 26 (emphasis added).

buildings in Washington, and the Coalition's suggestion that the same conclusion would apply in Oregon.[71]

Third, as explained in detail in Company witness John Taylor's Reply Testimony (NW Natural/1800, Taylor), the Rocky Mountain Institute study of a home in Seattle is also inapposite because there are important differences between the electric generation mix serving Seattle (more than 90 percent hydroelectric) and the electric generation mix serving most Oregonians.

NW Natural continues to believe that E3's Oregon Study discussed in our testimony provides the best available information for Oregon produced to-date, but at a minimum, the competing studies cited by the Coalition confirm the need for additional analysis before making significant policy decisions.

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[71] *See, e.g.*, Kavya Balaraman, *'Imagine the unimaginable': How the Pacific Northwest is trying to build a reliable grid in a changing climate*, UTILITY DIVE (Nov. 8, 2021), https://www.utilitydive.com/news/pacific-northwest-reliable-grid-changing-climate/608959/ (discussing efforts to plan and maintain grid reliability, including through constructing new transmission, as extreme weather, changing climate, and electrification efforts create uncertainty and challenges); John Harrison, *One big detail could derail Northwest's clean-energy goals*, THE COLUMBIAN (Mar. 27, 2022) https://www.invw.org/2022/03/29/one-big-detail-could-derail-northwests-clean-energy-goals/ (discussing need for additional transmission, the challenges of constructing new transmission, and the lengthy timeline required to do so). To understand the challenges with permitting a transmission line of this type, the Obama administration identified certain transmission projects for "expedited permit streamlining" in 2011. *See* Jon McCaull, *Obama Administration Fast Track for Transmission Projects Does Little for Western Geothermal Interests,* RENEWABLE ENERGY WORLD (Oct. 28, 2011) https://www.renewableenergyworld.com/baseload/obama-administration-fast-track-for-transmission-projects-does-little-for-western-geothermal-interests/#gref. Over a decade later, two of the projects, Boardman-to-Hemingway and SunZia, are still in the permitting process, and another transmission project, Cascade Crossing, failed to make it past the permitting process. To date, PacifiCorp has only been able to build a portion of its Gateway West transmission project. A transmission project, such as Boardman-to-Hemingway would need to be replicated many times over to add several GW of transmission import capacity to the Pacific Northwest.

Q. To be clear, what additional analysis does the Company contend is needed before Oregon's policymakers can make informed decisions as to the best path to decarbonization?

A. In order to make responsible policy determinations, we need an Oregon-specific, detailed decarbonization analysis that incorporates HB 2021 and CPP targets, timelines and risks; the emissions and relative costs of different technologies and combinations, including hybrid heating systems; the feasibility and cost of electrifying transportation *and* buildings; the impacts of electrification on the reliability of the electric grid; and the comparative energy system resiliency risks of an all-electrification approach.

Q. Are there benefits to an energy future that relies on both gas and electricity—rather than electricity alone—that the Commission should consider when evaluating the parties' policy recommendations?

A. Yes. There are significant advantages to the continued use of an integrated energy system that relies on electricity and natural gas. Specifically, maintaining the direct use natural gas system would contribute to the reliability, resiliency, and capacity of Oregon's energy system.

Q. Please explain how the natural gas system contributes to the reliability of Oregon's energy system.

A. As coal plants retire and the electric system transitions to carbon-free generation, there are significant concerns that there will not be adequate capacity resources to serve Oregon's electric demand. Continued use of the existing gas system—

which currently serves roughly 70 percent of Oregon's space heating needs[72]—will help ensure that Oregonians have the utility service they need for their daily lives. In contrast, shifting significant load from the gas system to the electric system—as would occur by rapidly electrifying both transportation and buildings—only increases the risk that Oregonian's energy needs will not be met.

Q. Please explain how the natural gas system contributes to the resiliency of Oregon's energy system.

A. As extreme events become more common, having natural gas available as an emergency backup fuel could be critical to Oregonians' health and safety. Both electric and natural gas utilities inherently face risks that each must work hard to mitigate every day: extreme weather, system and equipment failures, wildfires, cyber threats, and technical outages. Neither system is without risk. Diversification and redundancy of our energy system provides the greatest opportunity to achieve our clean energy goals without sacrificing reliability. If, as parties advocate, Oregon's above-ground electric system serves all new homes, businesses, and facilities—along with all future transportation needs—the risk to customers from failure of that single system is very high. A 2021 report, prepared by Guidehouse and commissioned by the American Gas Foundation, outlines a number of incidents in recent years that support why two decarbonizing energy

[72] NW Natural/1702, Heiting-Bracken/72 ("[direct use] natural gas serves 68% of regional space-heating needs despite being the primary source of heating for just over half of the residential housing units in Oregon and Washington.").

systems will be important to energy system resiliency and recovery in the years to come.[73]

Two recent examples punctuate this point. In 2021, in Oregon, an ice storm severely impacted the power grid and hundreds of thousands of electric customers lost power during a time of very cold temperatures. NW Natural was able to continue serving customers with much-needed heat, hot water, and the ability to cook. As another example, California's electric grid faced a state of emergency in 2021, and the state was forced to build five new, temporary natural gas plants to meet peak demand and avoid blackouts.[74] This example shows that legislation like California's mandate for a 100 percent renewable electric system does not automatically mean that a reliable, carbon-free electric system will result, as CUB and the Coalition appear to assume. In fact, Oregon's HB 2021, which applies to the electric sector, has cost and reliability off-ramps that would allow utilities to continue to rely on natural-gas-fired generation.[75]

Q. Please explain how the natural gas system can contribute to the capacity of Oregon's energy system.

A. The natural gas system has significant existing storage capacity that could be utilized to store excess variable renewable generation on a long-term basis.

[73] *See* NW Natural/1703, Heiting-Bracken ("in all of these case studies, the gas system provided significant support to the energy system in maintaining resilience and ensuring that energy service was maintained to customers").

[74] Mark Chediak and Naureen S Malik, *California to Build Temporary Gas Plants to Avoid Blackouts*, BLOOMBERG (Aug. 19, 2021) https://www.bloomberg.com/news/articles/2021-08-19/california-to-build-temporary-gas-plants-to-avoid-blackouts.

[75] H.B. 2021 at 6-8.

Specifically, NW Natural's existing gas system will support "power-to-gas" technology, which uses electricity to create hydrogen gas from water through a process called "electrolysis." Hydrogen gas itself is carbon-free, so if the electricity used to produce the gas is carbon-free, then the product is non-emitting, and blending hydrogen gas with conventional gas reduces overall GHG emissions. Electrolysis can be timed to use renewable energy that might otherwise be curtailed when variable renewable energy production exceeds demand. In effect, this process stores excess electricity in the form of hydrogen gas for later use, and the hydrogen gas can be stored indefinitely in existing underground storage facilities, which is much more effective and cost-effective than batteries for longer-duration storage. In this way, NW Natural's modern and tight distribution system can safely move and store renewable molecules, thereby increasing the capacity of Oregon's energy system.

C. NW Natural can comply with the CPP while serving new customers.

Q. Both the Coalition and CUB argue that NW Natural will be unable to comply with the CPP if it continues to add new customers, or that doing so would be too costly. Are they correct?

A. No. We disagree with CUB's and the Coalition's claims that NW Natural cannot comply with the CPP while serving new customers. NW Natural has been working to decarbonize its system for over a decade and has a strong foundation already in place, including concrete plans to acquire significant RNG and hydrogen gas. While we are currently in the process of conducting robust modeling of CPP compliance in our IRP, our preliminary modeling completed in docket UM 2178 suggests that we will be able to comply with the CPP while adding new customers, and that, on a per-customer basis, it is likely cheaper for the average existing customer if additional customers are added to the system while NW Natural meets its emissions obligations.

Q. Both CUB and the Coalition have criticized NW Natural for seeking to continue with "business as usual," but you mentioned that the Company has been working on decarbonization for over a decade. Can you please explain?

A. NW Natural strongly takes issue with the suggestion that it is not addressing climate change in any serious fashion and merely continuing with "business as usual." On the contrary, for over a decade NW Natural has been focused on strategies for reducing its GHG emissions and has long been a leader in the industry in recognizing the need to respond to the challenge of climate change. NW Natural is prepared to meet the challenge posed by the climate crisis and intends to decarbonize its gas system and achieve carbon neutrality by 2050,[76] consistent with our customers' priorities and expectations. Given the challenges of electrification and the progress the Company has already made on a variety of fronts, parties' insistence that NW Natural will be unable to achieve its decarbonization goals or that the Company does not take the climate crisis seriously are unfair and unsupported.

[76] NW Natural/100, Anderson-Kravitz/11, 14.

Q. Can you please summarize the Company's past work to decrease emissions?

A. Yes. NW Natural was one of the first natural gas utilities to establish a decoupling mechanism in 2003 to align the Company's and its customers' incentives to reduce usage and, consequently, emissions.[77]

In 2007, NW Natural launched its Smart Energy program, becoming the first stand-alone gas utility to offer our customers a voluntary carbon offset program. The Company has roughly 10 percent of its customers enrolled in the program, who have funded over one million metric tons of emissions reductions.

In 2015, the Company was among the first to replace all cast iron and bare steel, making our system one of the tightest in the country. As a result, NW Natural's modern system is well prepared to safely incorporate renewable gasses.

In 2017, NW Natural was the first utility to establish a voluntary carbon savings goal from across the gas value chain associated with customer and company use—a goal we are now exceeding.

In 2018, NW Natural revised its gas purchasing practices to incorporate consideration of the GHG emissions of its natural gas suppliers and prioritize purchasing from suppliers that report lower GHG emissions from production. NW Natural is one of the first utilities in the nation to develop and implement an emissions-screening tool that allows us to analyze EPA Subpart W emissions data reported by U.S. producers and understand the carbon intensity of gas supplies.

[77] NW Natural/100, Anderson-Kravitz/13.

With this capability, we can include environmental impact as one of the key considerations in our supply purchases (alongside other key purchasing criteria such as price, credit worthiness and geographic diversity) and reward lower emitting producers with our contracts. Since implementing this scorecard, we have prioritized purchases from among the lowest-emitting producers, which has reduced the methane leakage rate associated with our purchases from the Rocky Mountain region by roughly 20 percent, avoiding methane emissions accounting for roughly 60,000 metric tons of carbon dioxide ("CO_2") annually.

Also in 2019, NW Natural was instrumental in the drafting and passage of Senate Bill ("SB") 98 to facilitate RNG procurement by natural gas utilities, and we are actively working to rapidly acquire a diverse portfolio of RNG resources—including the Lexington RNG project discussed in Anna Chittum's testimony in this case.[78] Our plans to procure increasing amounts of RNG under SB 98 and CPP obligations will help reduce the Company's emissions below current levels. NW Natural also has been testing renewable hydrogen gas over the past 18 months and will be requesting the Commission's approval of a renewable hydrogen pilot project in the near future.

Finally, through the Energy Trust of Oregon ("ETO"), NW Natural supports energy-efficiency improvements such as cost-effective equipment upgrades and insulation in homes and businesses, as well as building improvements that last for many years. While the original purposes of energy efficiency were to lower bills

[78] NW Natural/1100, Chittum/6.

and reduce peak resource capacity requirements, we now see it as a critical tool for emissions reductions and our modeling shows the benefit of expanded energy efficiency programs in the context of compliance with the CPP. In this area, NW Natural has been a leader in developing avoided cost calculation methodologies that better show the value of energy efficiency to NW Natural's customers, including proactively including expected environmental compliance costs years before they came to pass with the CPP, resulting in more energy efficiency showing as cost-effective for ETO programs. In 2019, NW Natural and its customers provided funding that covered approximately $30 million of ETO activities and generated nearly 5.5 million therms in energy savings.

Through all of these actions, and others, NW Natural has proactively and successfully taken steps to decrease its carbon-footprint. There is simply no support for the notion that the Company either is or intends to carry on with business as usual.

Q. Have these existing efforts put the Company in a strong position to comply with the CPP?

A. Yes. As a result of these existing efforts, we projected the emissions associated with customers' Oregon gas usage would decline even as new customers join the system. We further projected that even before passage of the CPP, meeting SB 98 RNG targets alone may be sufficient to comply with the CPP for the first compliance period (2022-2024).

Q. Despite these voluntary efforts, NW Natural still must comply with the CPP and significantly reduce its overall emissions, right?

A. Yes. Specifically, the CPP requires NW Natural to reduce regulated GHG emissions 50 percent by 2035 and 90 percent by 2050.[79]

Q. Did NW Natural file a Petition for Review of the CPP with the Oregon Court of Appeals?

A. Yes. While NW Natural has specific legal concerns with the CPP, the Company remains committed to decarbonizing and understands that, regardless of the outcome of the appeal, NW Natural will likely be subject to decarbonization mandates in the future. Moreover, NW Natural's customers support aggressive efforts to decarbonize its gas supply in a cost-effective manner. Therefore, we continue to analyze the best approach to decarbonization and to implement strategies to comply with the CPP and to work toward the Company's goal of being a carbon-neutral energy provider by 2050.

Q. Has NW Natural analyzed whether and how it can comply with the CPP?

A. NW Natural has conducted preliminary analysis in the context of docket UM 2178. That analysis was necessarily high-level due to the expedited timeline, and, because the CPP was not finalized at the time, the docket UM 2178 analysis used the decarbonization requirements from the draft CPP, which were less aggressive than the requirements that were ultimately adopted in the CPP.

[79] From a baseline that averages 2017, 2018, and 2019.

The Company is currently conducting more in-depth, rigorous analysis to prepare its IRP, which will be filed in July 2022. As Staff noted in the Fact-Finding docket Draft Report, "[a]ll parties agreed that the rigor and analysis that comes with a full IRP would be needed for more definitive modeling conclusions."[80] Assertions that the Company cannot comply with the CPP are not supported by the analysis completed in docket UM 2178 and are likely to be refuted by analysis in the next full IRP, and therefore, any action proposed in this case based on the conclusion that the Company cannot comply is inappropriate.

Q. Did the Company's preliminary analysis in docket UM 2178 suggest that NW Natural will be able to comply with the CPP?

A. Yes. In docket UM 2178, NW Natural modeled how the Company would comply with the CPP under a number of sensitivities with different assumptions as directed by Commission Staff.[81] Our modeling indicates we can comply with the CPP using a combination of reducing demand, decreasing the carbon intensity of our gas supply, and judicious use of community climate investments (CCIs) and a wide range of potential developments moving forward.[82] Although the final CPP rules included some provisions different than the draft rules upon which the docket UM 2178 analysis was conducted due to timing, our IRP analysis conducted to-date indicates the same strategies identified in the docket UM 2178 process will enable us to comply with the CPP.

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[80] Docket UM 2178, Staff's Draft Report at 10.

[81] Docket UM 2178, Staff's Draft Report at 8-9, App. A.

[82] *See* NW Natural/1704, Heiting-Bracken.

1. Demand-side Reduction Strategies

Q. Can you please explain at a high level how NW Natural envisions significantly decreasing demand?

A. Yes. We expect to further reduce demand in the future through a combination of energy efficiency measures that will include shell measures as well as advances in appliance technology. For example, we can work to encourage the adoption of dual-fuel "hybrid" heating systems and high-efficiency natural gas heat pumps. Over time and with the help of incentives, gas customers can replace their current gas furnaces and water heaters with either hybrid systems or natural gas heat pumps. We note that in docket UM 2178, Staff acknowledges an ongoing role for natural gas heating in Oregon's energy mix by specifically recommending that the Commission direct the ETO to expand training for vendors on electric *and* gas heat pump technology, including dual-fuel and gas-powered heat pump technology.[83]

Q. What is "dual-fuel" or "hybrid" heating?

A. In a "dual-fuel" or "hybrid" heating system, a natural gas furnace serves as the backup to an electric heat pump to supplement or serve the needs of a building during cold weather events. Dual-fuel systems are lower cost for customers to operate and are less emissions intensive than an electric heat pump backed up by electric resistance heating, and can reduce gas usage within a home in our climate by as much as 80 percent. Hybrid heating also helps address resource adequacy issues on the regional power grid by having natural gas utilities continue to serve

[83] Docket UM 2178, Staff's Draft Report at 27.

the majority of space heating demand during peak cold weather events while electricity provides space heating during milder heating periods.

Q. What are natural gas heat pumps?

A. Natural gas heat pumps are an existing technology for multifamily, commercial, and industrial applications. They are being rapidly developed for single family use and are expected to be available for that use beginning in 2023. Natural gas heat pumps use the heat of combustion to run a compressor that takes heat from the air. Natural gas heat pumps are up to 160 percent efficient and, unlike most electric heat pumps, do not require a back-up heat source at low temperatures.[84] Considering the delivery efficiency benefits of the natural gas system compared to the energy losses during electric generation, a 160 percent efficient gas heat pump is on par with a 467 percent efficient electric heat pump.[85]

Q. CUB testifies that the Company's CPP-compliance analysis is flawed and its plan to comply with the CPP is unreasonable because NW Natural's energy efficiency assumptions rely on new technologies that have not yet been commercialized—specifically natural gas heat pumps.[86] Please respond.

A. First, we would reiterate that the docket UM 2178 analysis is preliminary, and the Company's IRP will include a more robust analysis showing that we can comply with the CPP using a variety of technologies and strategies—not just through use

[84] NW Natural/1705, Heiting-Bracken/6, 28.

[85] *See* Confidential NW Natural/1706, Heiting-Bracken; NW Natural/1707, Heiting-Bracken.

[86] CUB/100, Jenks/4; CUB/102, Jenks/5, 9.

of natural gas heat pumps. If natural gas heat pumps ultimately are not widely adopted, the Company has many other strategies that can fill the gap.

Second, our preliminary modeling in docket UM 2178 considers how to substantially decarbonize by 2050, so it is reasonable to assume new technologies will be available over time. Similarly, utility-scale batteries now being built to support electric system reliability were not widely available and represented virtually no capacity on the electric grid a few years ago. If the utility-scale batteries had not been included in resource planning exercises at that time, they would not have shown as cost-effective resources to justify them being built as prudent resources today. Resource planning exercises have always scanned the landscape to analyze options for meeting customer needs in a least cost-least, risk manner.

Specific to natural gas heat pump technology, NW Natural has supported the Gas Technology Institute's ("GTI") research and development progress for gas heat pump technology. GTI has a long and proven track record of advancing innovative high-efficiency equipment solutions and has partnered with the USDOE and manufacturers to advance gas heat pump technology—providing a giant leap in efficiency with the potential for up to a 50 percent reduction in gas throughput.[87]

[87] GTI, *Gas Technology Innovations: Focus on Gas-fired Heat Pumps* at 24, 27 (Sept. 17, 2019) (available at: https://s3.amazonaws.com/ilsag/Gas_Tech_Innovations-GTI_ILSAG_09-17-19.pdf).

New advancements offer greater efficiency benefits at a size for use in commercial businesses and homes.[88]

NW Natural is also a member of the North American Gas Heat Pump ("NAGHP") Collaborative. Gas utility involvement in the NAGHP Collaborative is substantial, with membership now representing approximately 33 percent of the natural gas end-use market in North America. In 2022, in-home installation trials conducted by NAGHP member companies will conclude, with the next step of product commercialization targeting a 2023 and 2024 timeframe.[89] Northwest Energy Efficiency Alliance ("NEEA") is an active participant in the NAGHP Collaborative. Many of the same technical and market-transformation experts who delivered the electric heat pump to this market are now actively involved in the residential gas heat pump efforts. Not long ago, newer electric heat pump technologies were at this pre-commercialization stage, and the gas industry now

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[88] SMTI, *The New Anesi Gas Heat Pump* (Jan. 30, 2022), https://stonemountaintechnologies.com/the-new-anesi-gas-heat-pump/#:~:text=The%20Anesi%20Gas%20Heat%20Pump,replacing%20an%2080%25%20AFUE%20furnace; Enbridge, *More comfort, less climate impact*, https://www.enbridgegas.com/-/media/Extranet-Pages/Sustainability/Municipal-Solutions/Energy-Solutions-for-Muncipalities/gas-heat-pumps-sell-sheet.ashx?rev=a2da08d97dce435a8c6ffae72ee49366 (last visited June 5, 2022); Fortis, *Pilot program success stories*, https://www.fortisbc.com/about-us/projects-planning/future-of-energy-efficiency/success-stories (last visited June 5, 2022).

[89] NW Natural/1705, Heiting-Bracken/9. *See also*, *FortisBC brings high-efficient gas heat pumps into B.C. homes for the first time* (May 26, 2022), https://www.fortisbc.com/news-events/media-centre-details/2022/05/26/fortisbc-brings-high-efficient-gas-heat-pumps-into-b.c.-homes-for-the-first-time; *SMTI Delivers first Prototype to Canada for Tests* (Jan. 17, 2020), https://stonemountaintechnologies.com/smti-delivers-first-prototype-to-canada-for-tests/; *ThermoLift & FortisBC Launch First Residential Gas Heat Pump Field Trials* (July 6, 2021), https://ifnc.campaign-view.com/ua/viewinbrowser?m=1&mrd=131cdc060d0a0c63&n=11699e4c03b042d&od=3zf7714b4695370a5bd59788165fdad00e2dd216119a546b182589036b4e1a7920&rd=131cdc060d0a3156&sd=131cdc060d0a0c75; *SMTI Commissions 'Heat Pump Furnace' Field Test Prototypes* (Jan. 4, 2019), https://stonemountaintechnologies.com/smti-commissions-heat-pump-furnace-field-test-prototypes/.

has the benefit of lessons learned from the electric industry's experiences with this type of product launch.

Moreover, it is important to keep in mind that compliance with decarbonization requirements presents technological challenges for both gas and electric utilities. On the electric side, successful decarbonization will require widespread adoption of CCHPs that are not economically viable for the vast majority of consumers today. It will require those heat pumps to be properly installed and operated at modeled set points, with ongoing maintenance performed by a highly skilled contractor network to achieve the necessary emissions benefits assumed. Decarbonizing the electric grid requires a massive build out of new renewable resources, as well as distribution and transmission infrastructure that will face long and contentious community and environmental siting challenges. There will also be economic, environmental, and geopolitical obstacles to providing the level of battery storage needed for a functional electric grid reliant on renewable resources.[90]

In short, decarbonization will require a full transformation of the entire energy system, requiring both gas and electric utilities to invest and innovate extensively and more rapidly than ever before. No one knows exactly how this transformation will unfold over the next three decades which is why a diversified energy system serving existing and new communities that is driving toward a

[90] *See* IEA, *The Role of Critical Minerals in Clean Energy Transitions* (May 2021), https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions.

variety of decarbonization options as fast and cost-effectively as possible helps protect against high regret decisions.

Q. CUB testifies that electric heat pump technology for space and water heating is more efficient than natural gas.[91] How do you respond to CUB's claim?

A. End use equipment efficiency is not the appropriate metric—and is a very misleading one—to evaluate the relative value of different types of space and water heating equipment in the context of state decarbonization goals. Rather, the metrics that are most important are the cost to customers to heat their homes and business, and the emissions impact of doing so.

To understand why end use equipment efficiency is only one factor that impacts emissions and cost, it is important to understand that an electric heat pump having a higher efficiency in percentage terms relative to a gas furnace simply means that the gas furnace uses more energy (British thermal units ("Btu")) *in the equipment* to heat a building with gas as compared to electricity. However, when one considers that on a per-Btu basis NW Natural's customers pay roughly one-third the price of electricity per Btu and that electricity used in Oregon has roughly three times as much GHG emissions associated with each Btu used, it becomes clear that simply comparing the end use efficiency of a natural gas furnace (approximately 95 percent) to an electric heat pump (approximately 250 percent) is incomplete and inappropriate in the context of understanding the emissions impact of heating a home or business.

[91] CUB/100, Jenks/2-3.

Another way to evaluate this issue is to consider the source efficiency of natural gas use between gas used directly and electricity that was generated using natural gas.[92] A simple cycle natural gas power plant is roughly 30 percent efficient and a combined cycle gas turbine is roughly 50 percent efficient. If one assumes that the average efficiency of natural gas generation serving Oregon is 40 percent, with five percent line loss, serving an electric heat pump that is 250 percent efficient (per CUB's testimony[93]), the entire heating system is around 95 percent efficient—roughly the same efficiency as a direct use natural gas furnace that is connected to the same natural gas network as the power plant that generates the electricity.

Thus, the more appropriate way to compare space and water heating technologies is using the metrics shown on the figures presented earlier in this testimony that compare the emissions and lifecycle costs of gas furnaces and electric heat pumps.

With respect to electric heat pump efficiency, as E3 explained in the California Study: "Electric heat pumps are an efficient means to deliver heating and cooling, but the associated efficiency decreases as the outdoor air temperature drops."[94] In climates like Oregon, electric heat pumps nearly always have a backup heat source to maintain comfort in cold temperatures—most commonly an electric resistance furnace, which is about twice as emissions-intensive as a

[92] Roughly half of the natural gas associated with energy use in Oregon is not used directly but instead is used in generating electricity used by Oregonians.

[93] CUB/100, Jenks/2.

[94] California E3 Study at 15.

natural gas furnace and costs customers more than double to run. Specialized CCHPs are more effective in cold temperatures, but they are also extremely expensive to install—roughly double the cost of either a high-efficiency gas furnace or a standard electric heat pump per the ETO Study[95]—and must be oversized relative to standard HVAC installation practices to be able to serve all of the heating needs of a home or business during cold weather events.

Q. CUB testifies that customer preference for heat pumps is growing and that over time customers will install electric heat pumps, rather than gas furnaces.[96] Is CUB correct, and if so, is it valid to assume in your modeling that natural gas will have an ongoing heating role if customers prefer electric heat pumps?

A. CUB's assertion that natural gas customers will leave the system in large numbers and install heat pumps is not supported by gas connection data or the research cited by CUB. In fact, since 2012, those customers and non-customers surveyed who stated they would "definitely/probably" purchase an electric heat pump increased by only 2 percent from 36 percent to 38 percent,[97] despite substantial ratepayer and manufacturer heat pump promotion and incentives.

CUB also fails to account for the fact that in the future, customers may replace a natural gas furnace with a hybrid or natural gas heat pump. While we have not surveyed customers regarding their specific heat pump preferences, it is

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[95] ETO Study at ii-iii.

[96] CUB/100, Jenks/3, 6, 8.

[97] CUB/108, Jenks/22.

reasonable to assume that the same customers interested in installing an electric heat pump may also be interested in a hybrid or natural gas heat pump that also offers air conditioning—a main driver of heat pump interest.

Q. CUB also testified that NW Natural is already falling behind in its effort to meet the CPP through reduced demand, because NW Natural forecasted average use per residential customer of 602 therms/year in 2022 in its docket UM 2178 modeling, but in this case, NW Natural forecasts usage of 628 therms/year.[98] Please respond.

A. First, we note that the annual weather normalized usage per residential customer forecast in this case is 633 therms, not 628 as CUB states.[99] Second, CUB's assertion that the Company is "already falling behind" in its efforts to meet its compliance obligations is incorrect.[100] While it is understandable CUB would compare the average residential usage in this rate case with the work done in docket UM 2178, the discrepancy in the figure is explained by something other than CPP expectations or compliance action. The difference is caused primarily by different definitions of normal weather for the forecast in this rate case and for the forecast used in the modeling in docket UM 2178. The weather estimate included in this rate case that yielded a residential use per customer of 633

[98] CUB/100, Jenks/5.

[99] NW Natural/1400, Wyman/13.

[100] CUB/100, Jenks/5.

therms/year uses an expectation of colder weather over a year[101] than the estimate in the docket UM 2178 modeling of 602 therms/year. The estimate in this rate case defines normal weather as the daily average heating degree days for the past 25-years whereas the estimate in docket UM 2178 uses a climate change adjusted weather model to predict heating degree days for each year in the future. The former definition is more standard in rate cases and is supported by Staff in this case.[102] Regarding the latter definition, NW Natural is a leader in moving toward a climate change adjusted weather modeling approach in its IRP work and established a methodology in its most recent IRP Update that accounts for climate change in our normal weather definition. This approach was also supported by Staff and other stakeholders in that process.[103] Given that the climate is warming, the number of heating degree days in 2022 used to generate the load forecast in this rate case are greater than those used to provide the forecast in docket UM 2178, resulting in a higher load forecast in this case. Hence the difference in forecast has nothing to do with changing expectations for CPP compliance.

In addition, it is important to note that the rules for the CPP were finalized less than six months ago, and we are currently less than half a year into the first

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[101] All forecasts use the weather from what is defined as "normal" for each year in the forecast, like year 2022 in this discussion. No year has "normal" weather, but the general idea is that half of actual years will have colder weather than normal and half will have warmer weather than normal.

[102] *See* Staff/400, Bain/2, lines 2-6 ("Staff found NWN's load forecasts to be sound and reasonable after scrutiny with the only adjustment recommended to be continued discussion of appropriateness for the future inclusion of a COVID intervention variable for the Commercial UPC forecast.").

[103] *In re Northwest Natural gas Company, dba NW Natural, 2018 Integrated Resources Plan,* Docket LC 71, Staff's Opening Comments at 10-11 (available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=lc71hac162944.pdf&DocketID=21497&numSequence=60).

compliance year in the program. NW Natural has stated consistently throughout docket UM 2178 that the analysis completed in that docket is preliminary and a full analysis using the appropriate analytical tools, including a full risk analysis, is necessary to construct a compliance plan.

2. Decarbonizing the Company's Gas Supply

Q. You stated that decreasing the carbon intensity of the Company's gas supply will help NW Natural comply with the CPP. Can you please summarize the renewable supply options included in the Company's modeling that allow the Company to substantially decarbonize by 2050?

A. Yes, at the current time we expect to decarbonize our supply over time by adding biofuel RNG, clean hydrogen, and synthetic gas to our gas portfolio to comply with the CPP. Our preliminary modeling shows RNG from biofuels as the cheapest option for gas supply decarbonization until about 2030. The model also shows that hydrogen becomes cheaper, and hydrogen blending reaches the 20 percent targeted amount around 2035. In the 2040's, synthetic gas derived from hydrogen projects is estimated to be the least cost of the available options.

Q. Please summarize the Company's plans and progress with respect to RNG.

A. Since the passage of SB 98, NW Natural has moved rapidly to study and acquire RNG developed from animal, agricultural, forestry, and human waste streams—which we will refer to as biofuel RNG—as a substitute for conventional natural gas. In this way, biofuel RNG turns captured emissions from existing waste streams currently contributing to atmospheric methane release into a powerful climate solution using the existing pipeline network and appliances, sustainably solving a waste problem at the same time. As discussed in the Company's Opening Testimony, SB 98 has RNG portfolio targets for natural gas companies to add as much as 30 percent RNG, including biofuel RNG and renewable hydrogen.[104] In less than two years from rules being implemented, NW Natural's gas portfolio has reached approximately one percent RNG, and the Company has already signed agreements to develop three percent of its supply as RNG.[105] Putting this swift progress into context, wind and solar generation nationally are 12 percent of electric generation after decades of development.[106] The Company aims to increase the amount of RNG it sells to customers to five percent by 2025 and to 10 percent soon thereafter, consistent with the targets in SB 98.

Q. Please provide some background regarding hydrogen gas.

A. The term "hydrogen gas" refers to the hydrogen molecule ("H2") in a gaseous state. It can be blended with natural gas to produce heat for homes and businesses and for industrial applications. This includes hydrogen gas blending into the existing system directly, distribution of synthetic gas at unlimited amounts, or dedicated hydrogen gas networks for certain customers or even new communities in the future. Hydrogen gas has been successfully delivered to

[104] NW Natural/100, Anderson-Kravitz/13-14.

[105] These percentages are a share of NW Natural's gas supply portfolio, comporting with the rules established in OPUC docket AR 632, and do not include gas delivered – but not sold – by NW Natural on transportation rate schedules. It is important to note that gas delivered on transportation rate schedules is part of NW Natural's covered party obligations in the CPP and that deliveries on transportation schedules represent more than one-third of the energy delivered by NW Natural's system in a given year.

[106] U.S. Energy Information Administration, *Electricity explained* (Apr. 19, 2022), https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php.

customers through gas distribution systems for over half a century. One example is Hawaii Gas which has been using about a 12 percent blend of hydrogen gas since the 1970s in its natural gas distribution system without issue.[107]

NW Natural is actively working to develop hydrogen gas supplies to incorporate into its system. As discussed in detail in the Company's Opening Testimony, NW Natural has one of the most modern and tightest systems[108] in the country and is well prepared to safely distribute natural gas blended with hydrogen gas.[109] For the last 18 months the Company has successfully completed five percent hydrogen gas blend tests in our system and in end-use equipment at our Sherwood training facility. In 2022, testing protocols will increase by five percent increments with the goal of 15 percent by year end and 20 percent by 2023, pending performance verification. The Company is also working in partnership with Eugene Water and Electric Board and the Bonneville Environmental Foundation to propose the development of a 1 MW electrolyzer project in Eugene, Oregon. There are a growing number of similar U.S. projects already underway,

[107] Hawai'i Gas, *Decarbonization and Energy Innovation*, https://www.hawaiigas.com/clean-energy/decarbonization (last visited June 5, 2022). In the 1970s, Hawaii Gas began producing and using hydrogen to convert naphtha, a by-product from the local oil refineries, for the manufacture of synthetic natural gas on the island of Oahu. Today, up to 15 percent of the gas in its Oahu pipeline is hydrogen—the highest concentration of hydrogen reported by any gas utility in the U.S.

[108] NW Natural consistently leads the industry in the lowest number of leaks per mile of distribution pipeline—a ratio of approximately 0.80 leaks per 100 miles in 2020. For comparison, the industry average was 7.65 leaks per 100 miles in 2019, based on U.S. DOT Annual Report data for natural gas operators reporting more than 7,000 miles of distribution main.

[109] NW Natural/100, Anderson-Kravitz/15-16.

including:[110] Centerpoint Energy has a 1 MW electrolyzer project and New Jersey Natural Gas has a 175 kW electrolyzer project, both projects deliver five percent hydrogen gas; [111] Pacific Gas & Electric has announced its "Hydrogen to Infinity" transmission blending study and demonstration facility;[112] and SoCal Gas has a solar hydrogen home now under construction.[113] NW Natural is also following and analyzing data through an international hydrogen consortium, HyReady, from numerous projects that are integrating higher blends of hydrogen into gas systems.[114] According to the Hydrogen Council's Hydrogen Update released in February 2021, 228 large-scale hydrogen projects had been announced across the value chain, with 85 percent located in Europe, Asia, and Australia;[115] and more than 30 countries have hydrogen roadmaps, including 31 energy companies

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[110] More than a dozen North American utilities are actively working on hydrogen as a resource. Some have hydrogen already being blended in (Enbridge and NJNG), some are under construction (CenterPoint), and others are looking at pure research and development. These include Atco, Chesapeake Utilities, Enbridge, CenterPoint Energy, Dominion Energy, Enbridge Gas, National Grid, New Jersey Resources, ONE Gas, San Diego Gas & Electric, SoCalGas, Southern Company Gas, and Southwest Gas. *See* American Gas, *The Hydrogen Race* (Apr. 2021), https://read.nxtbook.com/aga/american_gas_magazine/american_gas_april_2021/the_hydrogen_race.html.

[111] S&P Global, *New Jersey Resources starts up 1st East Coast green hydrogen blending project* (Nov. 10, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/new-jersey-resources-starts-up-1st-east-coast-green-hydrogen-blending-project-67570888.

[112] *PG&E Launches the Nation's Most Comprehensive Study on Hydrogen's Feasibility Within Gas Pipelines* (May 2, 2022), https://www.pge.com/en_US/about-pge/media-newsroom/news-details.page?pageID=66b8ed99-3175-48da-95d6-1a1fde0a4f18&ts=1651546270622.

[113] SoCalGas, *[H2] Hydrogen Home*, https://www.socalgas.com/sustainability/h2home (last visited June 5, 2022).

[114] DNV, *HyReady - Joint Industry Project*, https://www.dnv.com/article/hyready-219355 (last visited June 5, 2022). https://hydrogencouncil.com/wp-content/uploads/2021/07/Hydrogen-Insights-July-2021-Executive-summary.pdf

[115] Hydrogen Council, *Hydrogen Insights 2021* (July 15, 2021), https://hydrogencouncil.com/en/hydrogen-insights-2021/. The July 2021 update notes an additional 131 project announcements, bringing the total to 359. *Id*.

across 28 European countries that have analyzed how to re-use the existing gas system to distribute hydrogen by 2040 to help Europe achieve its decarbonization goals.[116]

These developments punctuate the increasing recognition globally that hydrogen gas in the gas system will be essential to achieving decarbonization of building load and the energy system.

Q. Please provide some background regarding synthetic gas.

A. In addition to renewable hydrogen gas produced from wind, solar, or hydro that can be blended directly and efficiently into the natural gas system, there are other forms of clean hydrogen gas that offer significant carbon benefits. Synthetic gas leverages renewable electricity and waste CO_2 from an industry process or power generation to produce a product that is interchangeable with conventional natural gas and can be distributed and stored without limits in the existing gas system. To put this into context: NW Natural's 20 billion cubic feet of underground storage at Mist, Oregon, equates to 6 million megawatt hours of renewable storage capability. To replicate this storage capacity as a battery would cost $2 trillion[117]—and it would still fail to provide the long-duration storage benefit of Mist. So, from a decarbonization cost perspective, synthetic gas can be very competitive when paired with the existing gas system infrastructure. Additionally, other hydrogen

[116] *See* Gas for Climate, *European Hydrogen Backbone* (July 2020), https://gasforclimate2050.eu/wp-content/uploads/2020/07/2020_European-Hydrogen-Backbone_Report.pdf.

[117] NREL, *Cost Projections for Utility-Scale Battery Storage* (June 2019), https://www.nrel.gov/docs/fy19osti/73222.pdf.

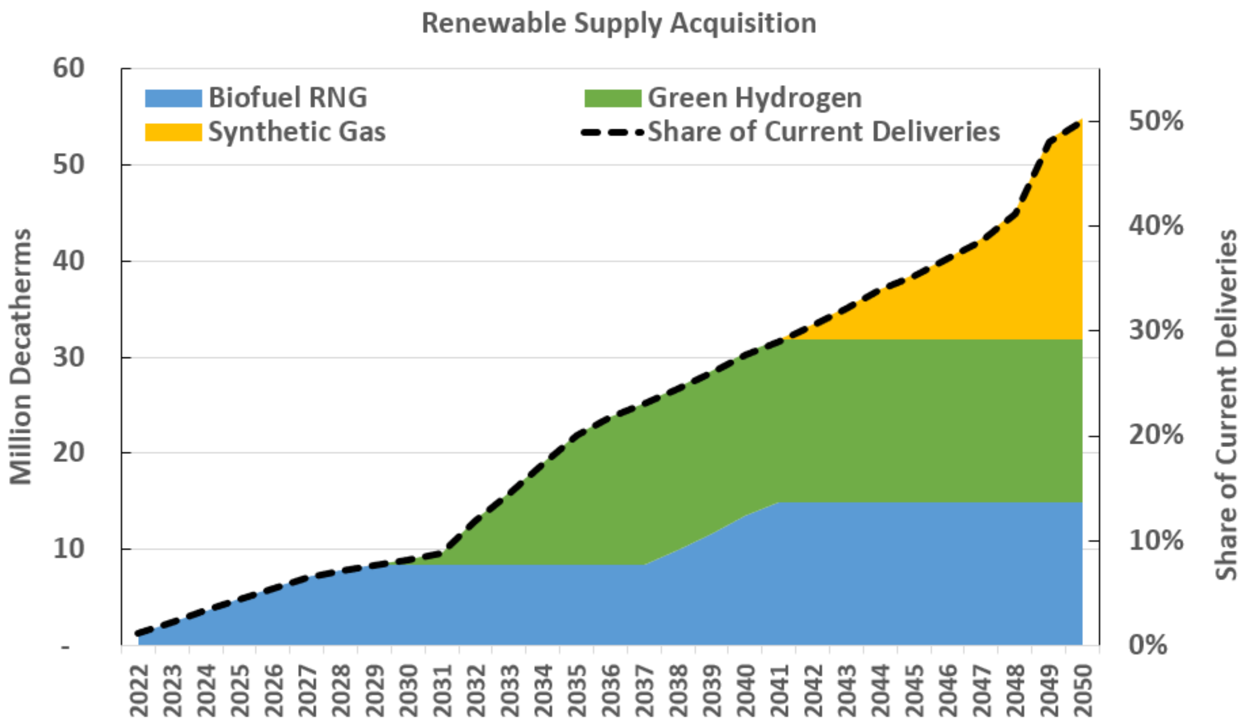
gas solutions look quite promising in the nearer term, including blue hydrogen produced from natural gas and paired with carbon capture, and turquoise hydrogen made using a process called methane pyrolysis to produce hydrogen gas and solid carbon, which can then be re-used in materials such as tires or batteries. NW Natural continues to actively research and assess all forms of clean hydrogen to inform its decarbonization plans and priorities.

Q. How do you respond to the Coalition's claim that there is not enough RNG to decarbonize NW Natural's network?[118]

A. To be clear, we do not envision serving customers with 100 percent RNG, even in 2050. Our preliminary modeling from docket UM 2178 deploys a cost-effective amount of biofuel RNG in 2050 at a volume that is less than 15 percent of current deliveries, as shown on the right side of the figure below from NW Natural's docket UM 2178 presentation.[119] We envision supplementing biofuel RNG with increasing amounts of hydrogen and synthetic gas as those products become more cost-effective, and the majority of deliveries in 2050 are expected to be from hydrogen-derived fuels.

[118] Coalition/100, Apter/15; Coalition/200, Burgess/19.

[119] NW Natural/1704, Heiting-Bracken/44.



In response to the Coalition's claims, we do expect to be able to obtain as much biofuel RNG as necessary to accomplish our decarbonization goals. As explained in Anna Chittum's Reply Testimony,[120] the study on which the Coalition relies was performed five years ago and does not reflect the potential for RNG today. More recent studies by the same group (ICF) project significantly increased amounts of RNG in the country. And as Ms. Chittum explains, the number of RNG projects operating and under construction, and RNG production capacity, has increased substantially since 2020.[121]

Looking to Europe, which leads in positive policy support for RNG, one can see the rapid growth potential to displace conventional supplies. For example,

[120] NW Natural/2100, Chittum/4-5.

[121] NW Natural/2100, Chittum/4.

Denmark has 25 percent of its total gas throughput as RNG today.[122] France is also expanding rapidly with more than 900 RNG projects identified throughout the country.[123] According to GRDF, France's largest gas utility, the total number of biomethane "projects recorded stands at 1,085, representing total capacity of 24 TWh/year."[124] This corresponds to the average annual consumption of 3.6 million new gas-heated housing units.[125] According to the French Environment and Energy Management Agency, by 2050, 56 percent of the gas circulating in the distribution grid could be RNG.[126]

Additionally, RNG development research is already finding different combinations of feedstocks yield higher production rates, which is likely to further increase overall supply and reduce costs.[127] Finally, it is important to note parallels to renewable energy acquisition in the context of Oregon's aggressive policy requirements. Just as Oregon electric utilities already have, and expect to

[122] *Bioenergy*, https://stateofgreen.com/en/focus-areas/energy-transition/bioenergy/ (last visited June 5, 2022).

[123] *Biomethane: the future of natural gas*, https://www.grdf.fr/english/biomethane-main-projects (last visited June 5, 2022).

[124] Id.

[125] Id.

[126] *Id.*

[127] *See* C. Okoro-Shekwaga, A. B. Ross, M. A. Camargo-Valero, *Improving the biomethane yield from food waste by boosting hydrogenotrophic methanogenesis*, 254 APPLIED ENERGY (Nov. 14, 2019) (available at: https://core.ac.uk/display/226768620?source=2); Jutta Speda,1 Mikaela A. Johansson, et al., *Enhanced biomethane production rate and yield from lignocellulosic ensiled forage ley by in situ anaerobic digestion treatment with endogenous cellulolytic enzymes,* 10 Biotechnol Fuels (May 2017) (available at: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5434626/); Brent Wittmeier, *New technique could accelerate waste-to-methane production*, UNIVERSITY OF ALBERTA (Jan. 10, 2020), https://www.ualberta.ca/folio/2020/01/new-technique-could-accelerate-waste-to-methane-production.html.

continue acquiring, more than their populated share of the nation's 12 percent wind and solar generation today, NW Natural is on a path to do so for RNG as well.

Q. CUB and the Coalition also question whether carbon-free gas supply options are available at a reasonable cost.[128] Are their concerns well-founded?

A. No. First, CUB compares the energy cost of carbon-free gas with the energy cost of conventional gas, which is an incomplete comparison of the costs of RNG versus conventional gas. NW Natural's low carbon gas evaluation methodology approved by the Commission compares the "all-in cost", or the total cost of delivering RNG or conventional gas to customers to make a more complete comparison. Additionally, CUB uses a near-term comparison of conventional gas and RNG prices without noting that low carbon gas prices—particularly hydrogen gas and hydrogen derived synthetic gas prices—are expected to decrease through time. Comparing the price projections of the third-party sources that were used for the modeling in docket UM 2178, the all-in cost of renewable hydrogen is expected to fall below the all-in cost of conventional gas by 2050. Also, given the fact that for residential and commercial customers the cost of gas currently represents a relatively small portion of overall revenue requirement, increases in the cost of gas are not expected to lead to unreasonable customer bills for gas service, particularly when compared to historical prices in real terms.

[128] CUB/100, Jenks/5; CUB/102, Jenks/4; Coalition/100, Apter/16.

Q. Do the Company's cost projections include assumptions about state or federal support for developing renewable gas?

A. No. Costs projected to date are without state or federal support. We anticipate, as recognition spreads for the necessity of a comprehensive approach to climate change increases and the associated need for RNG to assist in decarbonizing our economy is better understood, federal support will be provided for RNG, similar to what has enabled wind and solar development, thus bringing down the direct costs to our customers. In fact, NW Natural's preliminary modeling in docket UM 2178 found that a 30 percent federal production tax credit for renewable gases could cut the incremental cost of these gases to customers roughly in half.

Q. The Coalition claims that any environmental benefits associated with RNG are "negated" because of methane leakage.[129] Is this a valid concern?

A. No. First, NW Natural's infrastructure is fully modernized. Corrosion-prone vintage pipeline types were replaced in the Company's system by 2016. System modernization is the most important step that a pipeline operator can take to reduce incidence of leakage. As a result, NW Natural has one of the lowest leak-rates in the country.[130]

Second, it is important to consider the alternative to capturing and using RNG in the gas system. According to the EPA, the interstate pipeline system

[129] Coalition/100, Apter/16.

[130] NW Natural consistently leads the industry in the lowest number of leaks per mile of distribution pipeline—a ratio of approximately 0.80 leaks per 100 miles in 2020. For comparison, the industry average was 7.65 leaks per 100 miles in 2019, based on U.S. DOT Annual Report data for natural gas operators reporting more than 7,000 miles of distribution main.

leakage rate is 1.4 percent.[131] Therefore, to transport RNG across interstate delivery systems, the potential losses via pipeline fugitive emissions would be 1.4 percent as compared to the potential 100 percent methane losses realized when an RNG project is not developed.

Third, methane emissions from the gas system have decreased significantly and we expect this trend to continue. Nationally, emissions from natural gas utility systems declined 69 percent from 1990 to 2019, even as gas utilities added more than 788,000 miles of pipeline to serve 21 million more customers, bringing the number of customers served to 180 million.[132] NW Natural will continue its work with others in the industry to further reduce methane emissions.

Q. The Coalition also worries that NW Natural "might invest in thermal gasification of energy crops and forest and agriculture residues and use methane from sources that would be better eliminated through alternative resource and waste management processes."[133] Is there a basis for this concern?

A. No. While it is not entirely clear what exactly the Coalition fears NW Natural will do, we assume they are worried that NW Natural will invest in growing crops specifically to convert them to biofuels. However, NW Natural has no intention of doing so, and this is not an approach included in the Company's docket UM 2178

[131] *See* USEPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2020* at 3-104 (2022) (available at: https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-main-text.pdf).

[132] American Gas Association, *2021 Playbook*, https://playbook.aga.org (last visited June 5, 2022).

[133] Coalition/100, Apter/16.

or IRP modeling. To the contrary, as discussed in Ms. Chittum's Reply Testimony (NW Natural/2100, Chittum), NW Natural is not acquiring RNG from crops grown specifically for that purpose and the Company has no intention of doing so.[134]

Q. The Coalition claims that NW Natural's strategy of investing in RNG will allow it to continue with business-as-usual and earn profit for shareholders while polishing its image.[135] Please respond.

A. NW Natural strongly disagrees with this characterization. As we explained previously, significant RNG investment is one of the Company's key strategies for decreasing the carbon-intensity of our product so we can meet the Company's vision of achieving carbon-neutrality for the energy we purchase and deliver to customers, meet the targets set in SB 98, comply with the CPP, and meet our customers' expectations. We will be held accountable by our regulators, customers, and investors to ensure these investments are prudent and provide emission-reduction benefits. In this way, RNG investments are no different than electric utility investments in the wind and solar generation also needed to decarbonize electric generation.

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[134] NW Natural/2100, Chittum/5.

[135] Coalition/100, Apter/17.

3. Cost of Complying with the CPP

Q. CUB and the Coalition express concern that the costs of complying with the CPP will cause significant increases in NW Natural's rates.[136] Do you agree?

A. Our preliminary modeling suggests that we can decarbonize our system at a reasonable cost. While the analysis indicates that the costs of CPP compliance are significant, the impact to the annual bill customers are expected to pay for gas utility service—which is a better metric than billing rates—over the thirty-year horizon is estimated to increase at a relatively modest level for residential and commercial customers. For example, we estimated the average residential customer bill would be nine percent higher and the average commercial bill 15 percent higher in 2030 under CPP compliance than in a world where the CPP were not established, which is not out of line with where customer bills have been periodically over the last couple of decades in real terms.

Q. Both CUB and the Coalition express concern that the rising cost of conventional natural gas will also render gas utility service unaffordable.[137] What is your response?

A. While natural gas prices are expected to remain higher this summer, they are forecasted to drop in 2023 as natural gas production increases, liquefied natural gas ("LNG") export slows, and storage levels increase.[138] The increase this

[136] CUB/100, Jenks/5; Coalition/300, Fain/30.

[137] Coalition/200, Burgess/16-17; CUB/100, Jenks/5-6.

[138] U.S. Energy Information Agency, *Short-Term Energy Outlook* (May 10, 2022), https://www.eia.gov/outlooks/steo/report/natgas.php.

summer is not expected to be prolonged due to the vast domestic supply of natural gas. It should also be noted that Oregon electric utilities rely on as much natural gas for power generation as all the gas utilities deliver to customers each year.

Q. CUB claims that NW Natural plans to increase its energy efficiency spending more than 20-fold as part of its modeled CPP Compliance.[139] Is this correct?

A. No. CUB states: "In 2022, NW Natural will spend about $22 million on energy efficiency. In 2025, it forecasts expenditures of about $124 million. In 2030 it is — forecasting around $200 million in energy efficiency, and it keeps growing to more than $400 million/year."[140] NW Natural is unable to interpret CUB's exhibit on which it is basing this claim; however, we can confirm that CUB is incorrect and has misinterpreted NW Natural's analysis. While it is true NW Natural is projecting a large increase in energy efficiency spending in order to comply with the CPP, it is nowhere near the scale CUB cites in its testimony. The highest annual cost associated with energy efficiency work is approximately $150 million in 2047—not $400 million. It is important to note that the analysis shows the highest annual cost *for the entirety of activities modeled for CPP compliance*, including energy efficiency, renewable supply resources, and payments for community climate investments is $331 million in 2047. This figure is best put in context through the projected impact on customer bills discussed in the previous responses and in

[139] CUB/100, Jenks 5.

[140] CUB/100, Jenks 5-6.

comparison to current revenues collected by ETO from PGE customers, a figure near $100 million annually.[141]

Q. Both CUB and the Coalition testify that adding customers to the gas system will increase the cost of CPP compliance, which will be passed on to gas customers.[142] Please respond.

A. While it is true that increased load will increase the *total* cost of compliance with the CPP *for* NW Natural as a covered party, what is more important is the amount individual customers pay NW Natural for gas service and how that amount changes under different possible compliance strategies or possible futures. Importantly, our preliminary modeling in docket UM 2178 showed that the average expected bills for customers were *lower* in scenarios with customer additions relative to scenarios where new customers are not allowed to connect to NW Natural's system—the more electrification assumed in the scenario, the larger the impact to the typical customer bill. Therefore, CUB's and the Coalition's concerns regarding the impact of adding new customers are unfounded, and their recommendations to change NW Natural's line extension policy would actually drive the increase in customer bills they are framing their policy recommendation as protecting against.

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[141] ETO, *2021 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors* at 30 (Apr. 15, 2022) (available at: https://energytrust.org/wp-content/uploads/2022/04/2021-Annual-Report.pdf) ($95 million was collected from PGE customers by the public purpose charge in 2021).

[142] CUB/100, Jenks/10-11, 14-15; Coalition/100, Apter/7, 9-10, 14-15; Coalition/200, Burgess/19.

Furthermore, to the extent that CUB is truly more concerned about total costs of CPP compliance—as opposed to cost-per-customer—that concern will drive policies that are opposed to both economic and population growth. NW Natural does not believe that it is either helpful or beneficial for the state to discourage new businesses or immigration, particularly when there is a path to decarbonization that can be achieved at a reasonable cost per customer. Moreover, if CUB's logic were extended to Oregon electric utilities' need to comply with HB 2021, we would have to conclude that electric utilities should not seek to electrify transportation or buildings, as doing so would necessarily require more investment to serve this additional load while meeting the emission-reduction requirements of HB 2021.

D. CUB's and the Coalition's claim that significant numbers of customers are or will leave the system is without basis.

Q. Please summarize parties' claims regarding customers leaving NW Natural's system.

A. Both CUB and the Coalition point to factors other than cost that they claim are driving customers from the gas system, and based on these perceived trends, CUB and the Coalition argue that adding new customers may or will result in stranded costs, and therefore may no longer be prudent. CUB specifically raises the concern that customers are increasingly replacing gas furnaces with electric heat pumps such that fewer and fewer customers will be required to pay for the fixed costs of the system.[143] CUB also questions whether it is appropriate to assume that the useful life of a pipe is 60 years or more.[144] The Coalition claims that objections to natural gas as a fossil fuel[145] and concerns about indoor air quality[146] will cause customers to depart leaving fewer and fewer customers holding the bag.[147] These claims are unsupported.

Q. Please respond to CUB's claim that customers are increasingly replacing gas furnaces with electric heat pumps, which could result in stranded costs.[148]

A. NW Natural disagrees that increasingly customers are choosing to live in all-electric homes and convert gas equipment to electric equipment. CUB provided no evidence to show that customers are actively leaving NW Natural's system or converting gas equipment to electric equipment at rates out of step with long term trends. The Company's data do not show an increasing trend to electrify in recent years. The best metric to understand customer choices is the actual choices customers make. The graph below shows the share of newly constructed homes that chose to connect to NW Natural's system through time as a share of building permits opened in the Company's service territory.[149]

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[143] CUB/100, Jenks/3, 6, 13-14.

[144] CUB/100, Jenks/6, 13-14.

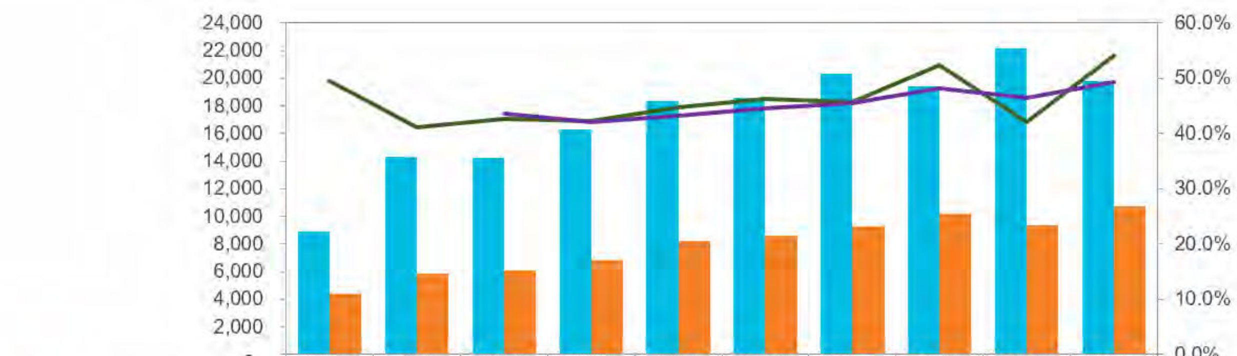
[145] Coalition/100, Apter/11.

[146] Coalition/100, Apter/14; Coalition/200, Burgess/20-21.

[147] Coalition/200, Burgess/17; Coalition/300, Fain/23.

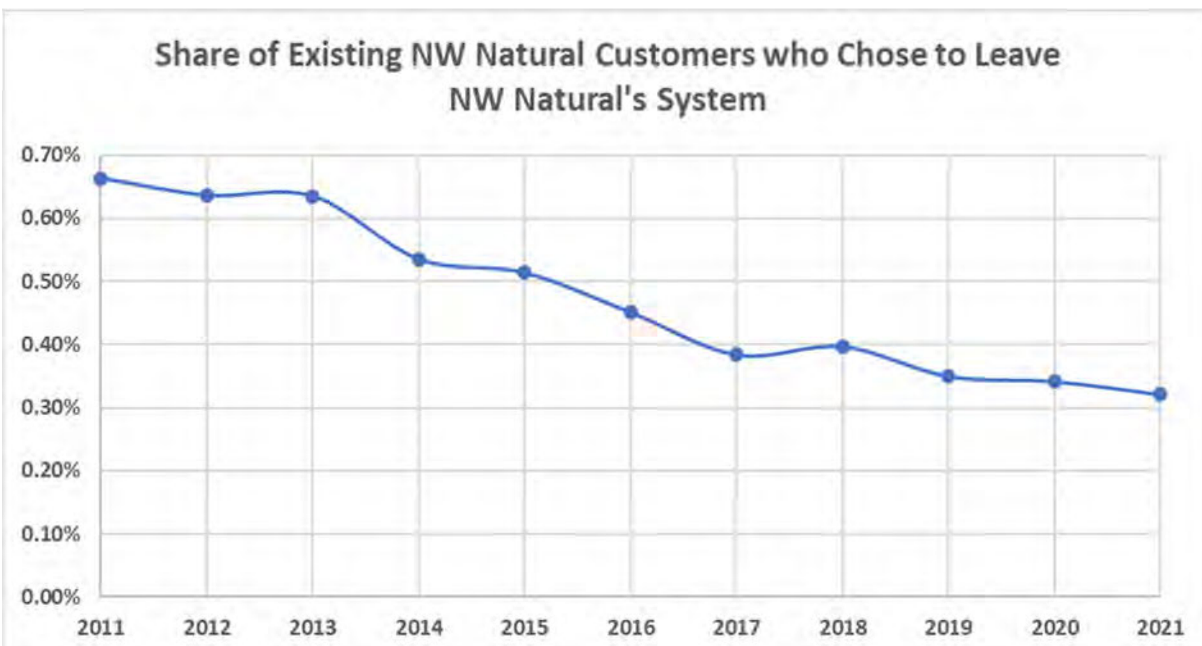
[148] CUB/100, Jenks/13-14.

[149] Note that not all new building permits are in locations that are served by NW Natural, even if in the Company's service territory.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Permits	8,924	14,328	14,209	16,273	18,365	18,577	20,353	19,458	22,181	19,811
Meters	4,419	5,894	6,052	6,871	8,227	8,589	9,312	10,203	9,345	10,730
Market Share	49.5%	41.1%	42.6%	42.2%	44.8%	46.2%	45.8%	52.4%	42.1%	54.2%
3-Yr Average Market Share			43.7%	42.0%	43.3%	44.5%	45.6%	48.1%	46.6%	49.3%

This data suggests that in the most recent years, newly constructed buildings have been connecting to NW Natural system at rates consistent with long-term trends. The following graph shows the share of NW Natural customers who left NW Natural's system (i.e. stopped being NW Natural customers) in a given year.



These graphs show that in recent years new customers have been choosing to connect to NW Natural's system at rates in step with the longer-term historical trend and that through time, fewer and fewer of NW Natural's existing customers have chosen to leave the Company's system, which is at odds with the assertions made by CUB and the Coalition. Additionally, while it is more difficult data to analyze, analysis suggests that NW Natural's customers who use gas as their primary space heating fuel are not converting to other fuels for space heating in recent years at a rate out of step with longer-term historical trends, either.[150]

Q. Please respond to CUB's and the Coalition's suggestion that customers *will* leave NW Natural's system or electrify their gas equipment due to public opposition to fossil gas.[151]

A. CUB and the Coalition argue that many factors will drive NW Natural customers to choose to leave the gas utility system entirely or electrify the gas equipment, particularly space and water heating, to electric heat pumps in support of their recommendation the Commission alter the Company's line extension policy. This conclusion about what customers will do is speculative and out of step with the response to the previous question.

Additionally, the Coalition's references to public opposition to proposed LNG export operations in the state are inapt.[152] NW Natural does not export LNG, and the Coalition does not explain how customer opposition to LNG export results

[150] NW Natural's data shows only usage of NW Natural's customers. If a customer stops using natural gas for space heating, the Company cannot say what the customer converted their heating to (be it a propane furnace, a wood stove, or an electric heat pump).

[151] Coalition/100, Apter/11.

[152] Coalition/100, Apter/11.

in customers declining to use natural gas in their homes and leaving Oregon's natural gas system.

Q. The Coalition also testifies regarding the health hazards associated with gas stoves.[153] Please respond.

A. I would start by pointing out there are no documented risks to respiratory health from proper use of natural gas stoves, including associated combustion related emissions, by the government agencies and advisory committees responsible for protecting residential consumer health and safety, including the Federal Interagency Committee on Indoor Air Quality and the Consumer Product Safety Commission. What federal agencies and peer-reviewed scientific studies conclude is that proper ventilation when cooking with <u>any</u> fuel source is the most important step you can take to mitigate potential cooking-related indoor air quality problems, because cooking activities themselves (*e.g.*, grilling, frying, broiling, baking) are a source of indoor air emissions, including particulate matter—which is why kitchen exhausts are required for <u>all</u> new homes, whether they have gas or electric cooking. In other words, you need to properly ventilate when cooking on a gas or electric stove to address potential cooking-related health concerns. Conversely, if you removed your gas cooktop for an electric one, but do not properly ventilate, you will still have a potential air quality problem. We believe this critical omission by the Coalition and others advocating for electrification is

[153] Coalition/100, Apter/14; Coalition/200, Burgess/20-21; Coalition/400, Ryan/22.

irresponsible because it leaves the public with misinformation that could negatively affect their health.

This issue has been misrepresented by advocates for electrification. The reports cited by the Coalition and funded or influenced by anti-natural-gas groups, such as Sierra Club and Rocky Mountain Institute, have clear methodology and testing protocol shortcomings that lead to many unsupported or misleading conclusions. These shortcomings are addressed in the attached Exhibits.[154]

Q. Do the parties' proposals in this case help address their concerns regarding stranded costs resulting from customers leaving the system?

A. No. CUB's and the Coalition's proposals to phase out or eliminate the line extension allowance would cause a decrease in the Company's customer base over time, which in turn would yield the very result about which the parties are concerned—increased costs for remaining customers. Thus, rather than responding to a phenomenon that is already occurring (customers leaving the system), CUB and the Coalition are actually recommending a policy change that will cause the phenomenon to occur in the future (fewer customers in the future).

[154] *See* NW Natural/1708, Heiting-Bracken; NW Natural/1709, Heiting-Bracken.

Q. CUB requests that the Commission phase out the presumption of prudence associated with capital investments to add new customers.[155] How do you respond?

A. As an initial matter, I am not certain I understand Mr. Jenks's statements regarding the "presumption of prudence" and what specific change(s) to the Company's tariff, the Commission's rules, or the State's statutes he is proposing. While NW Natural is required to extend service to new customers within its service territory, it must do so prudently and consistent with its tariff.[156] To the extent Mr. Jenks is suggesting NW Natural should *not* be required to serve new customers or permitted to recover for the costs of serving new customers under the terms of its tariff, this would be a drastic change with potentially drastic consequences.

E. Other Issues

1. Lobbying and Political Activities

Q. Please describe your understanding of the Coalition's arguments related to NW Natural's lobbying and political activities.

A. Based on my understanding of the Coalition's testimony, the Coalition is arguing that NW Natural is improperly seeking cost recovery of lobbying and political activities related to local jurisdictions' climate policies, the CPP rulemaking, and statewide legislation.[157] After the Coalition describes these activities, *to which I will respond below*, the Coalition states that NW Natural admits to seeking recovery

[155] CUB/100, Jenks/14-15.

[156] OAR 860-021-0050(1), OAR 860-021-0051.

[157] Coalition/400, Ryan/39-41.

of its recent engagement with the City of Eugene relating to the City's climate action plan.[158] The Coalition does not specifically assert that NW Natural has sought recovery of any of the other activities mentioned in this section of its testimony.

Q. How do you respond to the Coalition's argument?

A. I strongly disagree with the Coalition's testimony and the argument that the Company is inappropriately seeking cost recovery of political and lobbying activity. The Company has specific cost allocations for employees that are engaged in lobbying and/or political activity. These allocations (inclusive of salary and overheads) are recorded to non-recoverable expense. In other words, NW Natural has not sought recovery of those costs, and consequently, NW Natural's shareholders have paid for those activities. In response to a Coalition data request, NW Natural demonstrated that all employees in the Government Affairs department had specific allocations of their time recorded to non-recoverable expense.[159] In addition to salary and payroll costs, the Company records any costs of production of materials and communications to a non-recoverable account, and does not seek recovery of those costs either.

[158] *Id.* at 41.

[159] *See* NW Natural/1711, Heiting-Bracken.

Q. Please describe the Company's engagement with the City of Eugene regarding its climate action plan.

A. Over the past three years, NW Natural has been in conversation with the City of Eugene regarding their efforts to adopt and implement a climate action plan. As part of the climate action plan discussions, concerns about the environmental impact of gas service were raised, and in particular regarding whether the City should propose a prohibition on the addition of new customers to the gas system and other electrification measures. The City raised these concerns with NW Natural in the context of negotiations between the Company and the City regarding NW Natural's franchise agreement. In the course of these discussions, the City and its staff have asked the Company to provide a significant amount of information that would bear on their decision as to whether or not to move forward with regulating the provision of natural gas as part of their emissions-reduction strategy. The Company has provided the requested information via emails and meetings, has been invited to make presentations to the City, and has expressed many concerns about the negative implications of prohibiting their citizens from receiving natural gas utility service. Furthermore, as part of those discussions, NW Natural and the City engaged in many productive conversations to develop a targeted emissions reduction program for the City, which would be brought forward to the Commission for review and approval. Ultimately, those discussions did not lead to a program proposal, but they were conducted with the specific aim to provide solutions for the City's desire to decrease its emissions.

Q. Has the Company sought to recover the costs of its engagement with the City of Eugene in this rate case?

A. Yes, to the extent that the Company is seeking recovery of our standard employee compensation costs from the Base Year, the time working with the City of Eugene would be included in those costs.[160] The Company has not sought any special recovery for any costs associated with its work with the City of Eugene (such as a deferral of incremental costs not previously captured in rates).

Q. The Coalition's testimony also refers to political advocacy related to the City of Eugene including a "paid survey" and the "paid advertisements in a local newspaper."[161] Has the Company sought recovery of those costs?

A. No, the "paid survey" and the "paid advertisements in a local newspaper" were recorded as non-recoverable expense and paid for by shareholders. In fact, the survey referenced by the Coalition expressly states: "This communication and research are not paid for by customers."[162] While the Coalition did not provide an exhibit of the local newspaper advertisement, the Company's practice is to record any advocacy advertisement in a newspaper to non-recoverable expense.

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[160] The Multi-Party Stipulation entered into by NW Natural, Staff, CUB and the Small Business Utility Advocates reflects a reduction to revenue requirement for salary, wages and benefits of $5.25 million, which reduced the amount for which the Company seeks recovery of the wages of all employees, including those participating in negotiations with the City of Eugene. Docket UG 435, Stipulation at 5 (May 31, 2022).

[161] Coalition/400, Ryan/39.

[162] Coalition/408, Ryan/179.

Q. The Coalition also references the potential for other cities to regulate the use of natural gas.[163] Can you please provide some background regarding this issue?

A. Several cities in Oregon are grappling with the question of what they can do to address climate change, and some of them have explored the questions I have addressed in this testimony—whether the gas system should be expanded and to what extent electrification is feasible and/or beneficial. And some stakeholders in those conversations have indeed recommended limiting the growth of the gas system. We are often invited to comment on these ideas and plans as they are being developed not only because our customers could be impacted, but also because our expertise as a local distribution company is needed to fully understand the impacts of these proposals (regardless of the political outcome of any proposal). We have attempted to work with the cities to explain to them the importance and value of the energy we provide and what we plan to do to decarbonize, as well as the implications of a "gas ban". Importantly, no city has advanced a gas ban for new customers. We expect that cities will continue to have these conversations, and that we will need to demonstrate to them the value of our service, the role our infrastructure currently plays, as well as our ability to meet the State's decarbonization goals. We remain optimistic that when in possession of the relevant information, recommendations to limit gas service will be unsuccessful.

[163] Coalition/100, Apter/12-13.

Q. The Coalition testifies that the Company's costs of participating in the CPP rulemaking should be disallowed as "lobbying" and "political activities."[164] Could you start by describing the Company's participation in the CPP Rulemaking?

A. Certainly. Throughout 2021, the Company actively participated in the Oregon ODEQ's CPP rulemaking. As a covered entity subject to the then-forthcoming regulation, NW Natural provided the ODEQ with important information regarding NW Natural's service and product, listened and learned from the other participants, and responded to requests for comments for the agency rules. Additionally, NW Natural was invited to have an employee be a member of the Rules Advisory Committee.

Q. Please explain whether the Company views its participation in the CPP rulemaking as lobbying and whether it seeks to recover such costs in customer rates.

A. First, while I am not a lawyer, my understanding is that, by definition, the Company's activity in the rulemaking was not "lobbying" because the Company was not attempting to influence a legislative action. Rather, as noted above, NW Natural participated in an administrative rulemaking because the Company was expected to be a covered entity subject to emissions compliance.

As a covered entity, the GHG reduction proposals considered and ultimately adopted by the ODEQ would have very significant impacts on our customers.

[164] Coalition/400, Ryan/39-43.

Therefore, it was critical that the Company participate in the development of the rules. It is undoubtedly true that the Coalition may disagree with some of the Company's views expressed in the course of that rulemaking—however that fact does not suggest that the Company was not required to participate as a regulated entity, or that its customers are not benefited from that participation. If the Coalition is truly suggesting that NW Natural should not be permitted recovery for the costs of engaging with state and local governments or regulatory agencies that affect its business, that is a radical and unprecedented position that would have significant and far-reaching consequences for all utilities.

To the extent that the Company is seeking recovery of the costs of our participation in the rulemaking, the Company is only seeking recovery of our standard employee compensation costs from the Base Year and escalated to the Test Year. The Company has not sought any special recovery for any costs associated with the rulemaking (such as a deferral of incremental costs not previously captured in rates).

Q. The Coalition lists several examples of the Company's communications to customers related to the CPP and its public comment process.[165] Did the Company seek recovery of any of these communications?

A. No. Each of the communications identified by the Coalition were recorded as non-recoverable expense and paid for by shareholders. In other words, the costs of the communications were not included in the Base Year for recovery in this case.

[165] Coalition/400, Ryan/40; Coalition/408, Ryan/56-61, 63.

Q. Ms. Ryan also refers to the Company's involvement in general statewide legislative advocacy, presumably out of concern that the costs of these efforts were included in rates.[166] Does the Company seek recovery of its lobbying expense?

A. No, it does not. Specifically, the Company does not seek recovery of 50 percent of the employee compensation for our State and Federal Government Affairs manager. This allocation was established to reflect this employee's time spent lobbying.

2. Dues and Memberships

Q. What expenses are included in the Company's expense category for dues and memberships?

A. The expense category for dues and memberships includes dues paid to organizations where membership is necessary for the Company and its employees for perform their job functions (e.g., the Oregon State Bar and Oregon Board of Accountancy). In addition, these expenses include dues and memberships paid to organizations that:

- provide educational opportunities for NW Natural employees (e.g., American Institute of Certified Public Accountants and the Practicing Law Institute);

[166] Coalition/400, Ryan/41.

- certify NW Natural employees for specialized job functions (e.g., the American Board of Industrial Hygiene and the Institute of Internal Auditors); and
- provide opportunities to build and maintain relationships with other entities operating in the natural gas industry, such as the American Gas Association ("AGA"), Northwest Gas Association ("NWGA"), Western Energy Institute and the Better Business Bureau.

Q. Has the Coalition objected to the Company's request to recover expenses related to dues and memberships?

A. Yes. The Coalition's witness, Ms. Ryan, points out that the Company seeks to recover expenses related to dues and memberships in organizations that are involved in lobbying or other political activities, and therefore she argues that these expenses should not be recoverable.[167] In particular, Ms. Ryan asserts that the AGA and NWGA "engage in various lobbying and other political activities, including seeking to influence legislation or other government agency action and other political activities" that are not in customers' interests.[168] Ms. Ryan notes that the Company seeks to recover approximately $506 thousand in dues for these two organizations.[169] Ms. Ryan also points out that the Company has made payments to various Chambers of Commerce, the Oregon Truckers Association and other

[167] Coalition/400, Ryan/42-47.

[168] Coalition/400, Ryan/5, 43.

[169] Coalition/400, Ryan/42.

membership groups involved in political advocacy.[170] Ms. Ryan states that it is not clear how much the Company seeks to recover for payments recorded in accounts other than Account 930.2, but that she is concerned that the Company the Company is including these expenses as "above the line."[171]

Q. What adjustment does the Coalition propose to the Company's dues and membership expenses?

A. The Coalition requests that the Commission "disallow recovery of dues and payments to these trade associations as well as any other membership dues to third-party groups engaged in political activities."[172] However, other than noting the amount included in the Test Year for the AGA and NWGA (approximately $506 thousand),[173] the Coalition does not propose a total amount for its proposed adjustment.

Q. Did Staff also propose an adjustment regarding the Company's dues and memberships expenses?

A. Yes, however, Staff has entered into a multi-party stipulation with CUB, AWEC, SBUA (the "Stipulation"), and the Company addressing revenue requirement, rate spread and certain other issues. The Stipulation expressly resolves the adjustment that Staff proposed in its Opening Testimony regarding dues and

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[170] Coalition/400, Ryan/42.

[171] Coalition/400, Ryan 43. From Ms. Ryan's testimony, it appears that she mistakenly believes that dues paid to the AGA and NWGA are booked to FERC Account No. 930.2. While dues and membership expenses are booked to several FERC accounts, including Account No. 930.2, AGA and NWGA dues are booked to Account No. 921.

[172] Coalition/400, Ryan/5.

[173] Coalition/400, Ryan/42.

memberships by reflecting a reduction to expense of $443,000 that results in a reduction to revenue requirement of $456,000.[174]

Q. Please explain the Company's justification for recovering dues and memberships expenses in this rate case.

A. NW Natural believes that these organizations provide a benefit to NW Natural's customers and are a reasonable business expense that should be recoverable. These organizations keep employees informed and trained, provide opportunities to build and maintain relationships with other entities operating in the natural gas industry, and also, in many cases, directly take on issues that benefit customers (e.g., the AGA engaging in federal tax reform). They directly benefit employees' work performance, and in some cases are simply *necessary* for the Company's employees to perform their jobs and for the Company to operate.

Q. Please provide some examples of memberships that are essential for the Company's operation.

A. As noted above, the Company pays dues to the Oregon Bar Association on behalf of its lawyers and to the Board of Accountancy on behalf of its accountants. These dues are required for these employees to practice their professions. Another expense in this category is our subscription to the WebICE service. WebICE is an energy trading system that allows its members to see real-time natural gas pricing information at the various hubs where the Company purchases gas. This system

[174] Docket UG 435, Stipulation at 4.

allows the Company to track real-time pricing and ensure that its deals align with the market.

Q. Please describe the role of the AGA.

A. AGA's mission is to represent companies delivering natural gas, and to promote the safe, reliable, and efficient delivery of natural gas to homes and businesses across the nation. The AGA's activities include initiatives to improve the safety, efficiency and productivity of member companies' engineering and operating functions, such as:

- Technical Committees and Taskforces, addressing topics such as construction operations, cybersecurity strategy, enterprise risk management, gas control, and natural gas security.
- Technical Discussion Groups covering issues such as asset management, corrosion control, emergency management and public safety, emissions reduction and field worker assault prevention.
- Mutual Assistance Program and Emergency Planning Resource Center, which facilitates response, recovery, and restoration of services following a natural or other disaster.
- Technical Publications, regarding specific equipment, pipelines, gas measurement, leaks, etc.

A fuller summary of the AGA's key operational activities is provided in the Company's response to UG 435 Coalition DR 73, which is attached to this Reply Testimony as NW Natural/1711, Heiting-Bracken.

Q. Please describe the role of the NWGA.

A. The NWGA's mission is to advance the safe, dependable, and responsible use of natural gas, to foster greater understanding and informed decision-making among industry participants, opinion leaders, and governing officials in the Pacific Northwest on issues related to natural gas. The NWGA's activities include:

- Convening industry CEOs to share information about the industry.
- Public information through publications through speeches, seminars and conferences on important topics such as safety, alternative fuels for vehicle fleets and new alternative fuel technologies.
- Educational blogs and newsletters on industry developments.
- Developing collective industry perspectives on key regulatory issues, such as RNG gas quality.

Q. Does the AGA or NWGA engage in lobbying and other political activities?

A. Yes, both organizations engage in lobbying and political advocacy. However, as can be seen from the above, political work is just one area of activity among many others. For this reason, expenses related to dues and memberships are not booked to the FERC accounts reserved for lobbying and political activities.[175]

[175] Moreover, it is worth noting that while the Coalition may object to specific political activities undertaken by these organizations, there are others that they undoubtedly would support. For example, the AGA has been very active in seeking more energy assistance during COVID.

Q. Does the Company seek to recover expenses booked to FERC Account No. 426 as lobbying or political activity expenses?

A. No. As I stated earlier, consistent with Commission policy, the Company does not seek to recover such expenses.

Q. Please explain the function local Chambers of Commerce serve and the benefits the Company and its customers receive from membership.

A. Chambers of Commerce support local businesses, providing education and programs for members that address local challenges and opportunities including business recovery efforts, staffing and workforce development needs, and member education and local leadership programs. Utilities, both investor-owned and public, have traditionally participated in Chambers of Commerce; they are viewed as critical local infrastructure and economic partners for the communities and businesses we serve. As an example, PGE, PacifiCorp, and many electric Public Utility Districts also belong to Chambers of Commerce in our overlapping service areas.

Our membership in local Chambers of Commerce enable the company to stay involved with and create deeper relationships in the communities we serve, and they allow us to keep abreast of concerns, opportunities and challenges in our service areas, in an efficient manner including:

- Providing an efficient and effective way to engage, monitor, and interact with a large number of customers from across our service areas.

- Providing information and data we can use to assess our company program offerings (e.g., incentives, equipment preferences, energy efficiency needs, ability to respond to local policy aims)
- Communicating timely customer information including natural gas safety, free inspection reminders and maintenance tips, and billing assistance (e.g., communications around COVID-related customer arrearage management).

Q. Ms. Ryan raises the concern that the Eugene Chamber of Commerce opposed the City of Eugene's "electrification ordinances.[176] Does that fact suggest that there is anything improper about the Company's request to recover membership dues in that organization?

A. No. As I mentioned with respect to the AGA and NWGA, the fact that a Chamber of Commerce engages in political activity does not render the Company's membership an act of "lobbying"; nor does it suggest that the primary purpose of membership is political in nature. The Company views its membership in local Chambers of Commerce as a form of civic engagement, which is beneficial to the Company's customers.

[176] Coalition/400, Ryan/47.

Q. Please explain why the Company maintains a membership in the Truckers Association and the benefits to NW Natural and its customers associated with that membership.

A. As a critical component of its business, NW Natural maintains a fleet of vehicles that are used to provide utility service. Membership in the Truckers Association provides the Company with the following:

- Department of Transportation (DOT) Federal Motor Carrier Safety/ Administration (FMCSA) Regulatory Updates;
- DOT – FMCSA alerts for Emergency Declarations;
- Security updates for the Trucking and CDL regulated vehicles;
- Continuing Education, Training, and Safety Conferences to make sure we are in compliance with the FMCSA regulations;
- Networking with others in trucking and CDL-regulated vehicles, mainly to share best practices around Fleet Safety and Maintenance for trucks;
- DOT-FMCSA compliance audits to make sure NW Natural is in compliance with the regulations; and
- Experts for legal issues.

These are important benefits to help our employees perform their jobs safely and within all applicable regulations.

Q. Has the Coalition explained the specific political activity engaged in by the Truckers Association to which it objects?

A. No. However, to be clear, NW Natural's membership in the Truckers Association is not based on any political position that organization may take.

Q. How do you respond to Ms. Ryan's concern that the groups to which NW Natural pays dues and expenses are "inherently counter to the best interests of Oregon ratepayers and our climate"?[177]

A. I have two responses to this claim. First, I disagree that the policy recommendations of these organizations run counter to Oregonians' interests. I acknowledge that there are policy disagreements among the various stakeholders as to the best approach to decarbonizing this country's energy sector—and that the Coalition's recommendations may differ sharply from those made by the AGA, the NWGA's or the various Chambers of Commerce. However, that disagreement does not imply that these organizations are incorrect, or, more importantly, that the policies they espouse are counter to the interests of NW Natural's customers—who we believe benefit from these memberships.

Second, I disagree with the underlying premise of Ms. Ryan's argument, which is that customers do not benefit from NW Natural's membership in an industry if a stakeholder, or even NW Natural, disagree with one or more of the organization's policy recommendations. The membership of these organizations is extremely broad, and their policy recommendations generally represent the

[177] Coalition/400, Ryan/43.

majority opinion—so it is important that NW Natural participate and make its own voice heard. The bottom line is that AGA and NWGA are the primary industry organizations representing the interests of gas distribution companies, and as noted above, NW Natural's membership in these organizations is critical to keeping the Company's employees informed on industry trends, developments, and research.

Q. In addition, does the Stipulation already address the Coalition's concerns about lobbying and political activity expenses?

A. Yes. In its Opening Testimony, Staff proposed to disallow 25 percent of dues and memberships expenses for national and regional industry trade organizations, such as AGA and NWGA, "on the basis that certain activities are promotional or lobbying in nature or otherwise do not benefit customers"[178] and to disallow all memberships or dues paid to organizations that are neither industry research organizations nor such trade organizations.[179] Staff's total adjustment for dues and memberships expenses in its Opening Testimony was $443,905,[180] which is nearly identical to the $443,000 expense adjustment that the Company, Staff, CUB and AWEC agreed to in the Stipulation.[181] In offering this comparison, I am not presenting a position on Staff's adjustment in its Opening Testimony but rather am demonstrating that the Coalition's concern is resolved by the Stipulation.

[178] Staff/1200, Rossow/4, 6.

[179] Staff/1200, Rossow/6.

[180] Staff/1200, Rossow/6.

[181] Stipulation at 4.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

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June 6, 2022

Business

Oregon utilities face big challenges meeting 100% clean electricity by 2040 target

Updated: Jul. 21, 2021, 7:32 a.m. | Published: Jul. 21, 2021, 6:30 a.m.

PGE's Biglow Canyon wind farm. LC- The Oregonian

By Ted Sickinger| The Oregonian/OregonLive

Oregon just passed an ideologically and technically ambitious clean energy bill that directs its two largest utilities to deliver 100% clean electricity to customers by 2040 and prohibits new or expanded natural gas-fired power plants in the state.

The new law makes Oregon the eighth state to commit to 100% clean electricity, and along with New York, it now has the most ambitious timetable in the nation to get there. Utilities have signed on to the plan, which mirrors some of the targets to which they had already committed. And social justice and renewable energy advocates who helped structure the bill are also claiming a victory as the legislation includes minimum wage and apprenticeship requirements for developers, funding for community renewable energy projects, and a forum that will give them an ongoing voice in the utilities' clean energy plans.

In reality, however, no one, including the utilities, knows how they will achieve the bill's most ambitious targets, which stairstep from 80% clean electricity by 2030, to 90% percent by 2035 and 100% by 2040.

"If you go out to 2030, we think we can hit that," said PacifiCorp Senior Vice President Scott Bolton. "We were pretty clear though, beyond that we don't have a plan that shows we can get there."

Likewise, Brett Sims, a vice president at Portland General Electric, says the company had done a robust analysis showing it can meet the 2030 target by eliminating coal, operating its natural gas fired plants to serve peaks rather than base load demand, and adding substantial wind, solar, storage and demand reduction strategies to its resource mix.

The 2040 target, he said, remains aspirational.

Indeed, making "100 x 40" a reality will require major advances in technology, structural changes in energy markets and fundamental shifts in the way transmission is coordinated and sold. Even then, some believe there's a hefty dose of wishful thinking in House Bill 2021.

"This kind of legislation, while desirable from a carbon reduction standpoint, brings with it an enormous set of challenges that we haven't addressed yet," said Randy Hardy, an energy consultant and former administrator of the Bonneville Power Administration, the Portland-based federal power marketing agency that sells hydropower from dams in the Pacific Northwest and operates three quarters of the high voltage transmission system.

"You're betting on the come with technology," Hardy said. "It makes your planning significantly more complex, and the potential for error is that much higher...A significant portion of folks are underestimating the complexity and the cost."

HB 2021 allows "pauses" in meeting targets if the pace would cause reliability problems or become an economic hardship for ratepayers. And while the law prohibits new or expanded gas plants, it doesn't require utilities to shut down their existing plants.

While advocates have trumpeted the economic benefits and jobs that will flow from the bill, developers and other experts suspect the bulk of the renewable energy projects that result will be built out of state, where the reliability and economics of wind and solar are better.

Either way, customers and clean energy advocates are demanding that utilities decarbonize the grid. And with climate change visiting the whole of the west in the form of drought, wildfire and extreme weather events like last month's heat wave, the need is becoming more pressing, even as it complicates the task by placing increased demands and new risks on the grid.

Nicole Hughes, executive director of the advocacy group Renewable Northwest, acknowledges the revolution that needs to take place on many fronts to achieve a carbon free electricity grid by 2040. Still, she doesn't like the term 'aspirational.'

"I prefer 'inspirational,'" she said. "We've solved harder problems than this before."

This file photo shows the Outback solar farm outside Christmas Valley. Ted Sickinger/The Oregonian LC- The Oregonian

Building out wind, solar

In 2019, gas and coal-fired plants still furnished more than half of Oregon's electricity supply, though the total is likely somewhat lower today with the retirement of Portland General Electric's coal plant in Boardman. Replacing that capacity will require a vast buildout of wind and solar capacity. To increase reliability of those intermittent resources, that fleet needs to be geographically diverse and backed up by storage capabilities.

Oregon lawmakers included $50 million in funding for community based renewable energy projects in HB 2021. But in the scheme of things, that's a rounding error. And because Oregon's wind regime isn't as reliable as in Wyoming or Montana -- and the sun doesn't shine like it does in California or Utah – experts say much of that development is likely to take place out of state.

Witness the shortlist of renewable energy proposals that PacifiCorp recently submitted to regulators to meet renewables mandates and replace retiring coal plants. It included wind farms in Wyoming and Idaho and a huge chunk of solar in Utah. But out of the entire 3,250 megawatts of capacity, only 210 megawatts of solar, about 6% of the whole package, were in Oregon.

Oregon does have prospects. A recent study of how to decarbonize Oregon's electricity grid sponsored by a coalition of renewable energy advocates suggested the potential for as much as 20,000 megawatts of offshore wind projects in Oregon, about half of the peak demand that California's grid operator saw during a heat wave two weeks ago.

The Bureau of Ocean Energy Management, the federal agency that issues leases for offshore wind projects, has begun a multi-year scouting process in Oregon, collecting data on the best potential sites, environmental impacts and other risks. Because of deep waters off Oregon coasts, much of that development would be floating turbines, still a nascent sector of the industry. And the regulatory, permitting and financial obstacles are high.

"Is it offshore wind?" asked David Brown, co-founder of Lake Oswego-based Obsidian Renewables, primarily a developer of solar projects. "Maybe, but the first ones will be a really long approval process. We're years before anyone starts putting steel into the ocean."

Oregon isn't alone. California, Washington, Nevada, Idaho, Colorado and New Mexico are all pursuing similar goals, either through statewide mandates or individual utility plans. They're all chasing new sources of clean energy, and many of the utilities can afford to pay more for power than Oregon's because they charge more for it.

"If you add up all the policies passed, it adds up to an amazingly large buildout of renewables to meet them," said Ben Kujala, director of power planning at the Northwest Power and Conservation Council.

And that has significant implications for the way the grid operates today.

A major buildout of solar in California, for example, could displace demand for hydropower generated in the Northwest and even bring a flood of cheap solar power into the region. While that sounds good – more carbon free energy available here – operators are heavily constrained by fish requirements in how they run the dams, so they can't simply shift power production to when its needed. And Kujala says such a shift in the import/export dynamic would fundamentally change Bonneville's economics, potentially not for the good.

Three high voltage transmission towers, located just south of Sauvie Island, owned by PGE and Bonneville Power Administration (BPA). Mike Zacchino/The Oregonian LC- The Oregonian

Transmission expansion

Then there's the contentious prospect of building new transmission lines to move all that far-flung renewable energy to distant cities. In Oregon, that means more capacity to import power from states to the east, as well as additional capacity into California. Then you have to get the power the east side of the Cascades to population centers along the I-5 corridor.

Transmission lines are expensive, controversial and have a long lead time. In 2017, BPA cancelled an 80-mile, $1.2 billion transmission line dubbed the I-5 reinforcement project that would have run from Castle Rock, Washington to Troutdale. That came after seven years of study, and opposition from residents along the route concerned about the visual and noise impacts, the impact on their property values and easement negotiations.

Likewise, the $1.2 billion Boardman to Hemingway transmission line, which would run through eastern Oregon and Southwest Idaho, has been more than a decade in the making and generated deep opposition among farmers and conservationists.

Such pushback is virtually assured for any substantial new line, but utilities and renewable developers insist the clean energy transition won't happen otherwise. The existing pipes are getting full.

The federal government could help. The infrastructure bills being debated in Congress are likely to include direct support or tax credits for inter-regional transmission and potentially an extension of the production tax credit for renewables projects.

That raises another fundamental barrier to reaching the clean energy targets: the lack of a unified west-wide transmission system operator to coordinate and control a multi-state grid. Today, there are 34 so-called balancing authorities in the western United States, according to the U.S. Energy Information Administration -- a balkanized hodgepodge in which each utility plans to meet their own customer needs.

Renewable energy developers like Brown say they face multi-year lead times for utilities to complete studies of how they might interconnect new projects because there is no central repository of the knowledge. It's unclear if existing lines are being fully used because of the way transmission is contracted today, and no one is assigned to make it work for everybody.

Having one or two entities manage the grid, experts say, would allow utilities to access a much wider spectrum of complementary renewable energy resources, avoid duplicative investments in power generation and transmission, reduce grid congestion, and theoretically, enhance reliability at the lowest cost.

Previous proposals, however, have fallen flat in the Northwest amid fears California would big-foot other states and public utilities' worries that such a system would shift costs to them.

The region's investor-owned utilities have taken small steps in that direction, participating in an energy imbalance market run by California's grid operator that gives them access to a real-time energy clearinghouse to maintain moment to moment balance between electricity supply and demand. BPA plans to start participating in the market next year.

"You need to take advantage of the incremental measures underway and stairstep your way to a full-scale (regional transmission organization)," said Hardy, the energy consultant and former BPA administrator. "It's an enormously complicated project that you can't make happen overnight. Likely it's a post-2030 event."

Other technologies

Getting to 100% clean will lean on a variety of resources, not just wind and solar. PacifiCorp is exploring a small-scale nuclear reactor in Wyoming, though such plants remain expensive and controversial.

PGE talks of converting the turbines at its existing natural gas plant in Boardman to burn hydrogen, or a blend of hydrogen and natural gas. Both are unproven, potentially expensive, and have their own pollution problems.

Likewise carbon sequestration, where operators capture a plant's greenhouse gases and inject them into long-term storage, is an unproven science experiment.

One consequence of greater reliance on intermittent renewable resources is the need for more – and better -- energy storage technologies. Many of today's wind and solar farms include battery storage to smooth their output when the wind stops blowing or the sun goes down.

But with today's technology, even large battery arrays can only supply a limited amount of power for a few hours. During a winter cold snap or a west-wide heat wave, that won't cut it.

One viable alternative is pumped storage, which moves water into a higher-elevation reservoir during low demand and prices -- typically at night -- then taps the power during high demand periods by running the water downhill through hydroelectric turbines.

There are several pumped storage projects on the drawing board in the Pacific Northwest, but they haven't penciled out financially. The federal infrastructure bill may include production tax credits for pumped storage projects, which would make them more viable, though some face considerable environmental and tribal opposition.

Utilities also say they will rely heavily on so-called demand response -- voluntary programs that offer incentives for industrial, commercial and residential customers to reduce energy use during peak demand. Larger customers are offered discounted rates throughout the year in exchange for allowing their utility to reduce their consumption during peak events. Residential customers can participate in peak pricing programs or give the utility the ability to adjust their thermostats when demand is high.

PGE said 130,000 residential customers have signed up for such programs today. During last month's heat wave, when electricity demand hit a record, it was able to shave its load by 63 megawatts, enough to power 21,000 homes. Two-thirds of those savings came from residential customers.

The company is seeking to increase that potential to 200 megawatts by 2025, and more than 500 megawatts by 2030, about 15% more power than the peak output of its gas-fired plant in Boardman.

Getting anywhere near 100% clean electricity will also require a sustained commitment to residential and commercial energy efficiency, green buildings, more solar panels on homes and a host of other technologies.

All of this comes at a cost. And for many, it still leaves a fundamental question whether utilities could meet their customers' energy needs under all scenarios. It's a question no one can fully answer today.

"You can run the grid in almost any way you want if you're willing to spend a lot of money," said Kujala with the Northwest Power and Conservation Council. "You can do almost anything. You can be resource adequate. But it has cost implications."

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1702

June 6, 2022

Pacific Northwest Pathways to 2050

Achieving an 80% reduction in economy-wide greenhouse gases by 2050

November 2018

Energy+Environmental Economics

Pacific Northwest Pathways to 2050

Achieving an 80% reduction in economy-wide greenhouse gases by 2050

November 2018

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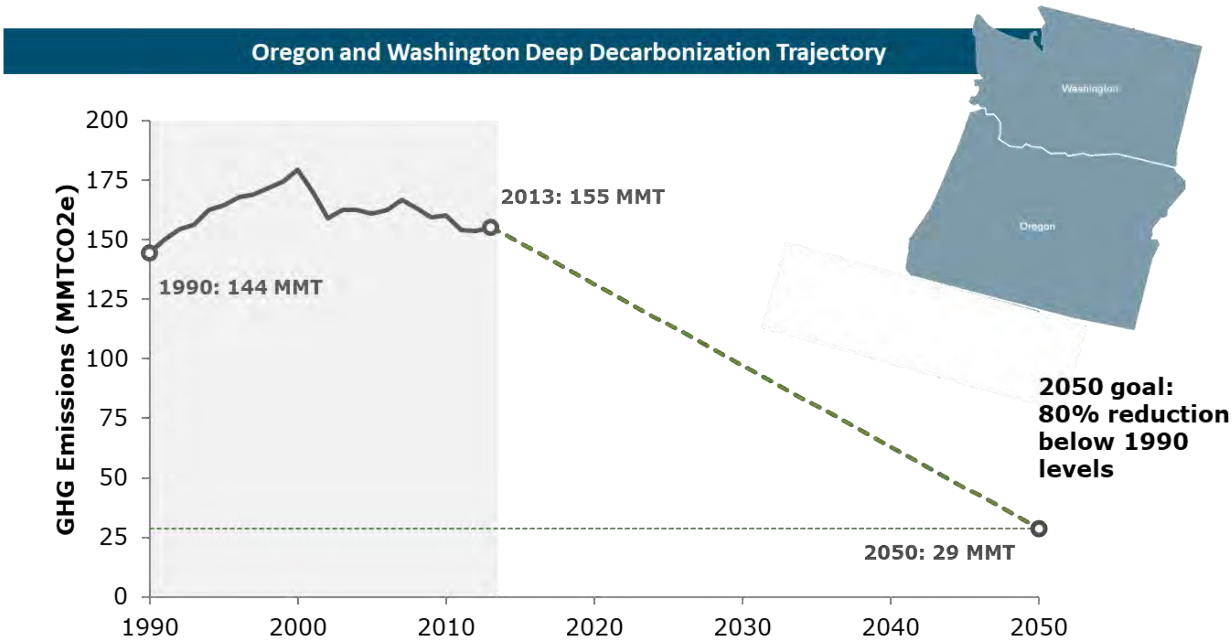
Executive Summary

Study Background

To help limit the worst impacts of climate change, Oregon and Washington have both committed to achieving significant reductions in greenhouse gas (GHG) emissions by 2050. Policymakers and the public are also contemplating new policies and programs to achieve steep regional GHG reductions.

This study evaluates the technology implications, and potential costs and savings, of different strategies to achieve long-term, economy-wide GHG reductions in Oregon and Washington. This study considers GHG emissions reductions of 80 percent below 1990 levels by 2050, a level of reduction often called "deep decarbonization." Achieving an 80 percent reduction goal across the two combined states would bring total regional economy-wide emissions down to 29 million metric tons CO_2-equivalent by 2050, compared to approximately 155 million metric tons CO_2e in 2013 (Figure 1).

Figure 1. Pacific Northwest historical greenhouse gas emissions and 2050 greenhouse gas target



This is an ambitious target. Achieving the carbon reductions envisioned in this analysis has implications for all residents, companies, and economic sectors in the region. NW Natural, as the gas distribution business serving most of Oregon's population and the Vancouver, Washington, area, has an abiding interest in both understanding the role of a natural gas company in achieving this low-carbon vision, and in helping to achieve the sustainability goals of its customers and the broader region. To address this, NW Natural contracted Energy and Environmental Economics, Inc. (E3) to perform an independent analysis of deep decarbonization scenarios for the Pacific Northwest.

This study builds on an existing body of research. Prior studies have evaluated options to achieve deep decarbonization in the United States as a whole, and in states like Washington and California. Similar studies have also been done at the sub-state level, including a recent deep decarbonization study of the Portland General Electric service territory. However, none of these prior studies, to our knowledge, has investigated the costs and implications of meeting winter peak energy needs during the region's coldest periods.

This study focuses on the role of buildings in meeting broad, economy-wide carbon reductions, and pays special attention to the performance of building space heating technologies under cold temperature conditions, and the costs of reliably serving those loads. The region's natural gas and electric systems are built to serve peak heating loads during cold temperatures that fall well below average winter conditions. Both the gas distribution system and the electric generation system experience the highest peak demands concurrently, during the winter. During the coldest days of the year, the natural gas system provides a large amount of energy to meet the region's heating needs.

A key question in this study is how the existing gas distribution system could be used to help achieve economy-wide deep decarbonization goals, while continuing to reliably meet regional peak energy demands. This low-carbon future is compared to what would be required of the region's electric system – already a winter-peaking system – if it were to take on the gas system's substantial winter peak heating loads. under a future where natural gas space and water heating were electrified.

Approach

The modeling approach applied in this project is based on E3's deep decarbonization scenario tool, called PATHWAYS. The economy-wide PATHWAYS framework is supplemented by tools tailored to specifically analyze the electricity sector, biofuel supply and conversion paths, and building energy performance. The Northwest version of the PATHWAYS model is tailored to regionally-specific energy demands, energy supply, and existing building types, vehicles, and other energy-consuming equipment, using local data whenever possible. The tool is also benchmarked to the Oregon and Washington state greenhouse gas emissions inventories.

PATHWAYS is an economic energy and greenhouse gas emissions accounting tool. A key feature of the PATHWAYS model is its detailed treatment of the Northwest's energy infrastructure. Energy infrastructure includes equipment that produces, delivers, and consumes energy, such as power plants, industrial facilities, trucks, cars, buses, and building equipment. While each sector and type of equipment consumes energy and produces emissions differently, collectively they determine the region's GHG emissions trajectory.

Costs, emissions, generation, and peaking capacity needs in the electricity sector are modeled in more detail using a separate electricity-sector tool called RESOLVE. RESOLVE is a power system operations and investment model that uses linear programming to identify optimal long-term resource investments in the electric system, subject to electric reliability and policy constraints. RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost electric sector investment plan, accounting for both upfront capital costs and variable costs to operate the grid. This project uses a Northwest-specific version of RESOLVE that was initially developed for the Public Generating Pool in 2017 and described in the "Pacific Northwest Low Carbon Scenario Analysis" report.[1]

Biofuels are an important component of long-term decarbonization plans because they represent carbon-neutral fuels that can be transported and used with existing infrastructure and equipment. Assumptions around biofuel costs and supply receive detailed treatment using the E3 PATHWAYS Biofuels Module. This tool generates biofuel supply curves that determine the availability and cost of renewable liquid and gaseous biofuels, and optimizes the selection of combinations of feedstocks, conversion pathways, and final fuels based on regional fossil fuel demands.

Finally, we evaluate the hourly performance of different types of electric heat pump space heating equipment, using regionally appropriate winter temperature conditions. E3 worked with building science

[1] E3, "Pacific Northwest Low Carbon Scenario Analysis: Achieving Least-Cost Carbon Emissions Reductions in the Electricity Sector," December 2017. Available at: http://www.publicgeneratingpool.com/wp-content/uploads/2017/12/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf

consultants at Big Ladder Software to simulate the performance of several different types of buildings and heat pump equipment configurations in two climate zones in the Northwest, using the building simulation software EnergyPlus. After accounting for load diversity and building shell improvements, we use hourly load shapes to modify the base, system-wide hourly load profiles in the RESOLVE model. This creates a more realistic picture of how hourly electricity demands, and winter peak electricity demands, could change under a high building electrification future.

This suite of modeling and analytical tools allows us to combine a least-cost scenario design approach for the electricity sector, with a detailed understanding of electric building performance, with an economy-wide, technology-specific perspective of costs, energy consumption and greenhouse gas emissions using the PATHWAYS model.

Scenarios and Key Findings

Four scenarios to 2050 are evaluated, which differ in their consideration of technology pathways to serve space heating needs in buildings. Two of the scenarios maintain the direct use of natural gas[2] in buildings (relying on gas furnaces or natural gas powered heat pumps), while two of the scenarios assume a large-scale transition and retrofitting of buildings to electric end-uses (relying on electric air source heat pumps or cold-climate electric air source heat pumps) (Table 1). All scenarios are constrained to achieve an 80 percent reduction in GHGs by 2050 for the Pacific Northwest regional economy, while assuming continued economic and population growth.

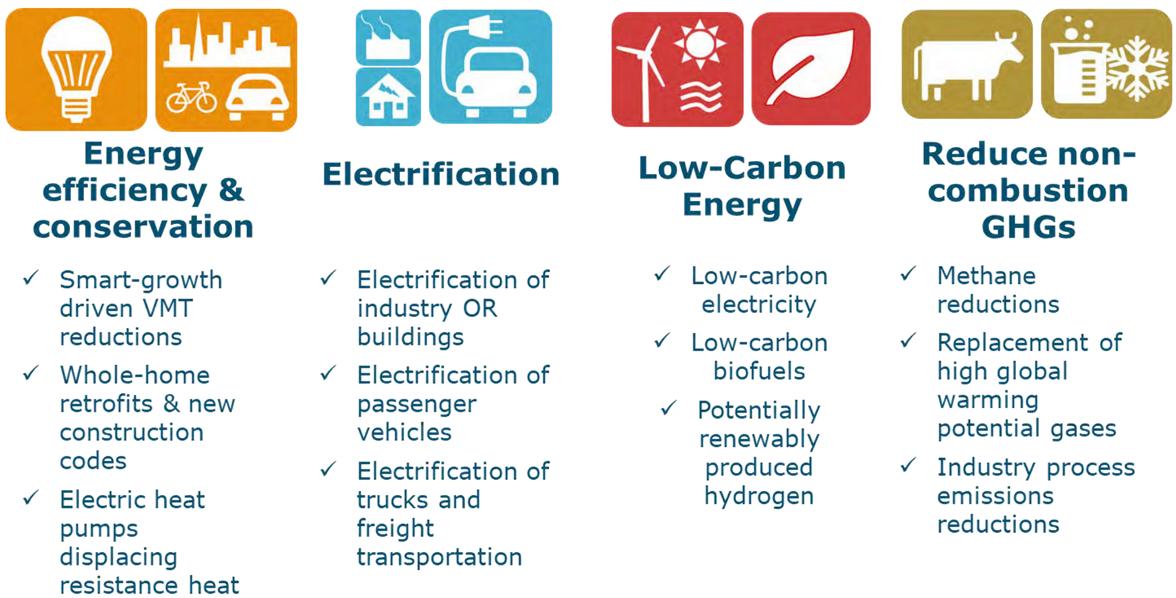
[2] Direct use of natural gas is defined as all gas that is not used to generate electricity.

Table 1. Key 2050 metrics by scenario

2050 metrics	Gas Furnace Scenario	Gas Heat Pump Scenario	Electric Heat Pump Scenario	Cold-Climate Heat Pump Scenario
Share of Natural Gas Space and Water Heating Electrified (fuel switching)	0%	0%	96%	96%
Industry Electrification (fuel switching, % total industry energy demand)	30%	30%	5%	5%
Carbon Free Electricity Generation	97%	97%	95%	95%
Biofuel Development (Share of available resource)	100%	97%	73%	73%
Hydrogen Mix in Gas Pipeline	7%	0%	0%	0%

These scenarios demonstrate that deep decarbonization in the Pacific Northwest will require transformative change to the energy economy of the region, across every sector of the economy. Four strategies, or "pillars," are identified as a common finding across deep decarbonization studies: energy efficiency and conservation, electrification (i.e., switching from fossil fuels to electricity), low-carbon energy, and reductions in non-combustion emissions (Figure 2).

Figure 2: Pillars of Deep Decarbonization

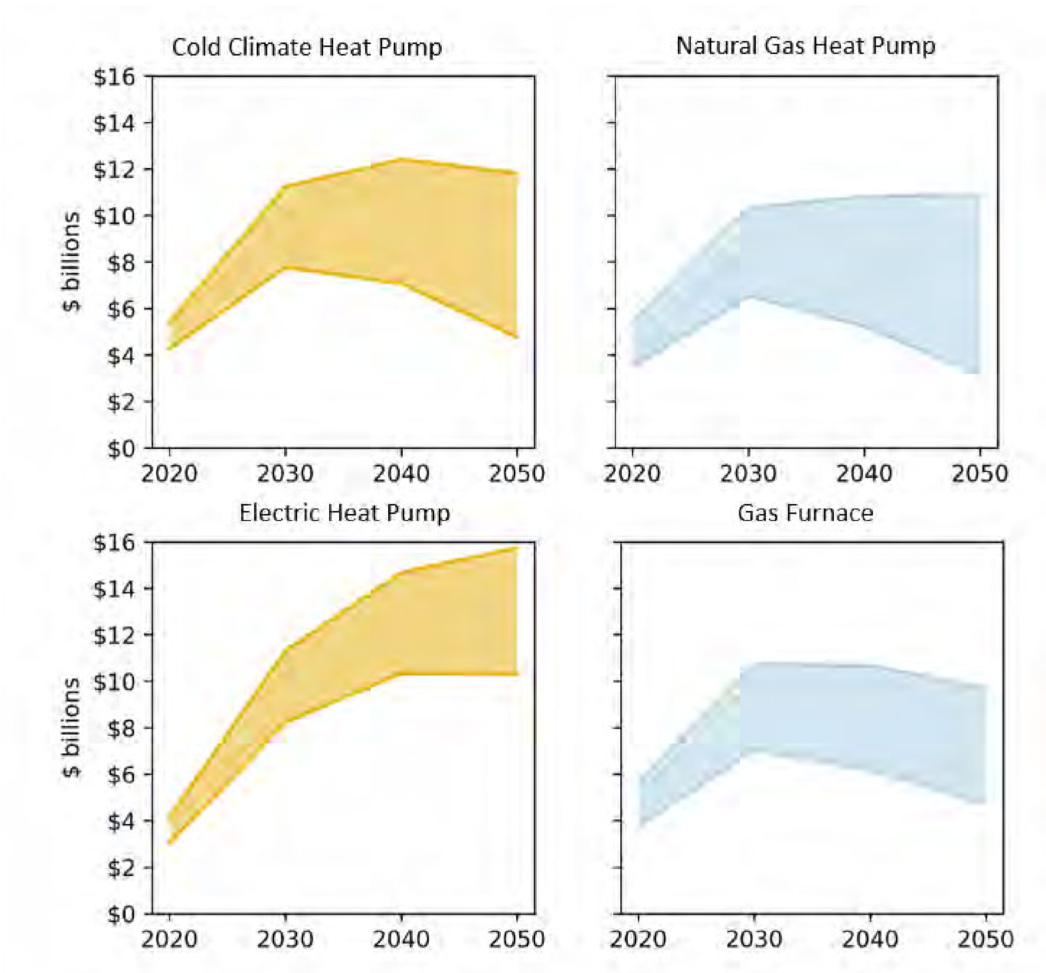


While all of the scenarios contain elements of each of these four pillars, not every measure is required in every scenario. The relative emphasis on each pillar differs by scenario. All of the scenarios evaluated in this study include high levels of building energy efficiency, including building shell improvements and deep energy efficiency retrofits, as well as reductions in vehicle miles traveled. All of the scenarios evaluated here include nearly complete electrification of the transportation sector as well as high levels of renewable and low-carbon electricity. All scenarios assume the same level of reductions in non-combustion GHGs. However, the scenarios differ in their levels of biofuels, renewable hydrogen, and in building and industrial electrification levels.

Total economy-wide scenario costs in 2050, relative to a reference or business-as-usual future, are similar between scenarios with one exception: the conventional (non-cold climate) electric heat pump scenario is most expensive, due to the high cost of serving winter peak demand (Figure 3). Overall, total scenario costs represent less than 1 percent of regional projected Gross Domestic Product (GDP). The average scenario costs range from \$40/ton to \$190/ton CO_2e in 2050 (in real 2017 dollars), relative to the Reference scenario depending on the future capital costs and fuel prices assumed. The average cost per ton metric means that some measures are far less expensive than this, while other measures are more expensive. This range reflects the wide range of uncertainties in projecting future scenario costs. Overall, these average GHG abatements costs (\$40/ton to \$190/ton CO_2e) are generally lower than the most recent estimates of the global social cost of carbon, which has a median cost of \$417/ton CO_2, (and ranges from \$177 to \$805/ton CO_2).[3] The global social cost of carbon represents the expected economic damages to be incurred by climate change, per ton of CO_2 emitted.

[3] Ricke, K., L. Drouet, K. Caldeira, M. Tavoni, "Country-level social cost of carbon," *Nature Climate Change*, Vol. 8, October 2018 895-900. Available at: **https://www.nature.com/articles/s41558-018-0282-y.pdf**

Figure 3. Annual mitigation scenario costs relative to Reference scenario, including capital and fuel cost sensitivities, 2020 - 2050



We find that all scenarios that achieve deep decarbonization face significant challenges, but the types of challenges are different. Scenarios that maintain gas heat in buildings require:

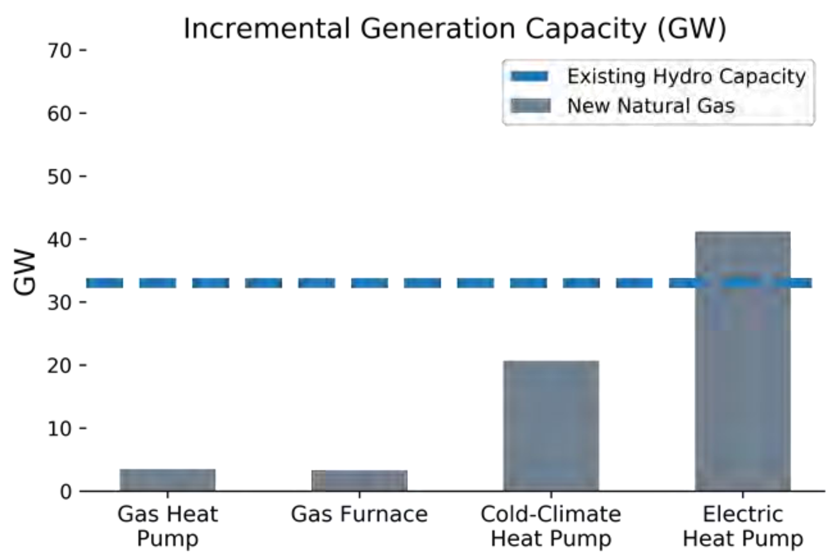
- ***Reducing the carbon intensity of natural gas use in buildings by blending in low-carbon alternatives, including up to 30% carbon-neutral renewable natural gas and hydrogen.*** While all of the scenarios evaluated here rely on carbon-neutral biofuels to meet the 2050 GHG goal, the use of renewable natural gas is of higher importance in the scenarios that maintain gas in buildings. Renewably-produced hydrogen or synthetic methane blended in the gas pipeline are also options to displace fossil natural gas.
- ***High levels of energy efficiency in buildings***, potentially with higher efficiency natural gas-powered heat pumps.
- ***Additional reductions in other sectors to offset higher emissions in the building sector.*** In these scenarios, additional reductions are achieved primarily through 30 percent of industrial sector energy switching to electricity.

The scenarios that switch to electric heat in buildings require:

- ***Rapid consumer adoption of electric heating technologies, including retrofits of existing buildings and broader commercialization and market transformation of cold-climate heat pump technologies.*** Conventional electric heat pump technologies are designed to maximize comfort and annual savings for the building occupants. This means that they require supplemental heat, typically electric resistance heat, during cold temperatures. At high levels of adoption, these heat pumps will place significant demands on the electric grid. In a high building electrification future, greater attention to heat pump installation practices and standards would be needed to mitigate the impact on the electricity system of meeting increased winter peak heat demands. Cold-climate electric heat pumps perform better during cold snaps than heat pumps not designed for cold climates, but they are less common today and have higher upfront costs. Absent other load management strategies, cold climate heat pumps do not eliminate the need for new winter peak electric generation and delivery capacity in a high building electrification future in the Pacific Northwest.
- ***Significant new investments to address winter peak demand from electric space heating,*** including an expansion of the electricity system in the form of upgraded distribution systems as well as winter peak capacity resources. In the scenarios that transition to electric heat in

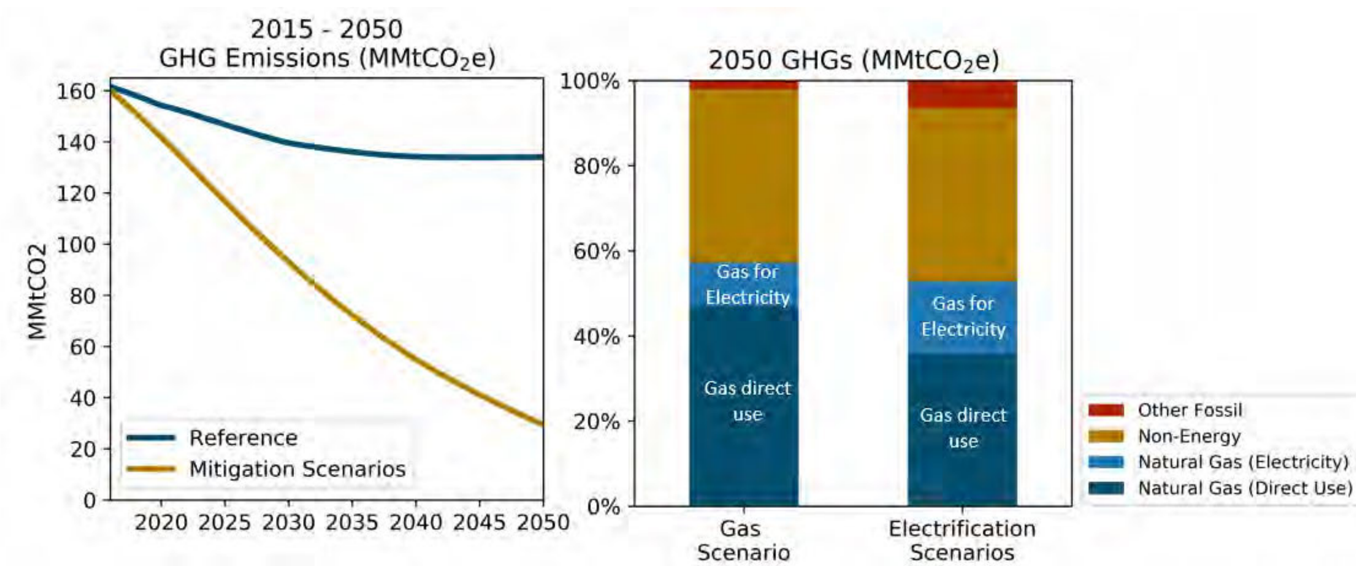
buildings, the widespread deployment of electric heat pumps leads to a five- to 10-fold increase in the incremental natural gas generation capacity build by 2050, relative to the Direct Use of Natural Gas Scenarios. This is equivalent to an additional 17,000 to 37,000 megawatts (MW) of additional peaking capacity need by 2050. Some of this winter peaking, gas-fired electric generation need could be displaced by energy storage, demand response, or technology innovation. But the cost of using batteries and other forms of electricity storage to meet winter peak heating needs is still unclear. For comparison, the entire hydroelectric system in the Pacific Northwest represents approximately 33,000 MW of installed capacity (Figure 4). Ensuring winter peak reliability will be a key planning challenge to address if building heating needs are increasingly electrified.

Figure 4. 2050 new firm natural gas capacity build by scenario, compared to existing regional hydroelectric capacity (gigawatts)



In all of the decarbonization pathways considered here, a combination of fossil and renewable natural gas, whether used in homes or in power plants, continues to serve winter peak heating needs in the Pacific Northwest (Figure 5). This study does not include an exhaustive investigation of alternative options to meeting peak heat demands. Potential alternative options are higher cost or more speculative as a peak capacity resource during extreme cold events in the region (e.g., geothermal heat pumps, energy storage, or incremental demand response).

Figure 5. Greenhouse Gas Emissions Over Time and 2050 GHG Emissions by Source and Scenario



Achieving a low-carbon future in the Pacific Northwest will require policies that encourage the development and deployment of next-generation energy technologies. Key areas for technology development and deployment highlighted in this study include:

- Deep energy efficiency and shell retrofits in buildings;
- Transportation electrification and electric vehicle charging infrastructure;
- Advanced forms of sustainable, carbon-neutral fuels, including renewable natural gas, renewable diesel, and renewable jet fuel;
- High efficiency space heating technologies, such as cold-climate heat pumps and natural gas heat pumps, that mitigate or manage winter peak impacts; and

+ Industrial sector GHG mitigation options, including energy efficiency, electrification, and fuel-switching, as well as renewably produced hydrogen.

Many pathways exist to achieving decarbonization in the Pacific Northwest. The challenge lies in the development and sustained deployment of the advanced technologies needed to transform the region's energy economy to a lower-carbon future over the next two to three decades.

1 Introduction

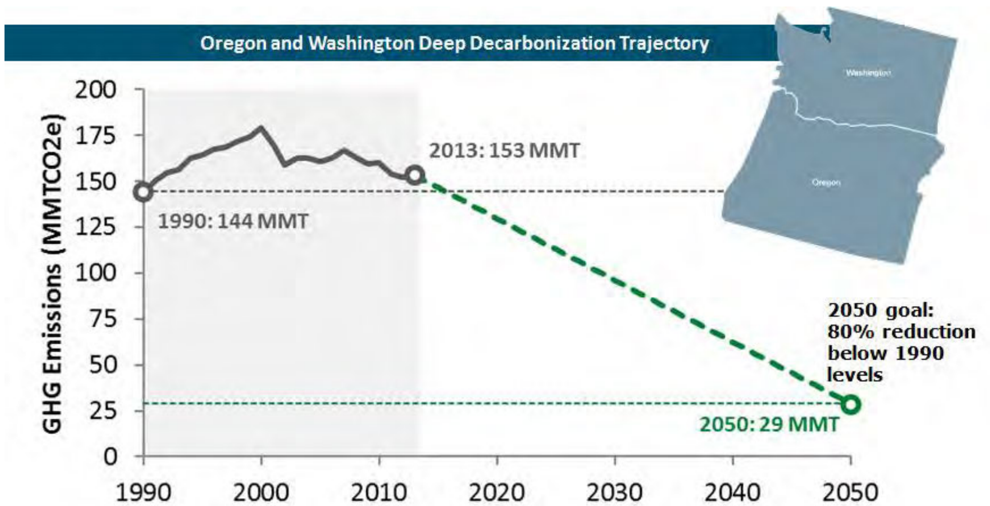
1.1 The Climate Context in the Pacific Northwest

1.1.1 CLIMATE GOALS IN OREGON AND WASHINGTON

Oregon and Washington are leaders on climate and clean energy policy. Both states are taking steps to reduce emissions with a portfolio of policies that encourage energy efficiency, expand renewable energy and support the deployment of battery electric vehicles. In 2007, the Oregon legislature passed House Bill 3543 which calls on the state to achieve greenhouse gas (GHG) levels that are at least 75 percent below 1990 levels by 2050. The Oregon legislature is now considering the development of a cap and trade program to reduce GHG emissions in the state further. In 2008, the Washington state legislature passed a law requiring a reduction in GHG emissions of at least 50 percent below 1990 levels by 2050, but in 2016, the Department of Ecology recommended a stricter limit. In the "Washington Greenhouse Gas Reductions Limit" report, the Department called for an overall GHG reduction of 80 percent below 1990 levels by 2050.

This study evaluates pathways for the Pacific Northwest, Oregon and Washington combined, to achieve an 80% reduction in greenhouse gases by 2050 (Figure 6). State-specific results for Oregon and Washington are included in the Appendix. This level of climate mitigation is often referred to as "deep decarbonization" and is consistent with the global reduction in greenhouse gas emissions that are necessary to limit global warming to 2 degrees Celsius.

Figure 6. Pacific Northwest historical greenhouse gas emissions and 2050 greenhouse gas goal



1.1.2 GREENHOUSE GAS EMISSIONS IN OREGON AND WASHINGTON

The largest share of greenhouse gas emissions in Oregon and Washington are from the transportation sector. Buildings represent the second largest source of GHG emissions in the region, nearly evenly split between emissions from electricity generation and the direct use of natural gas and petroleum-based fuels, such as propane. The remaining greenhouse gasses in the region come from both direct and fugitive emissions in industry, agriculture and waste.

Figure 7. 2015 Greenhouse Gas Emissions in Oregon and Washington by sector and fuel (source: PATHWAYS model)

1.2 Pathways to Achieve Deep Decarbonization

1.2.1 FOUR PILLARS

A common finding across the deep decarbonization studies completed in the US, globally, and in the Pacific Northwest is the use of four broad emissions reduction strategies to achieve deep decarbonization.

These strategies, or “pillars”, include: energy efficiency and conservation, electrification (switching fossil fuel powered infrastructure to electricity), low-carbon fuels, and reductions in non-combustion emissions. Any successful mitigation scenario will include reductions from each of these pillars, but not every scenario must include every measure from within a pillar. Scenario analysis offers the opportunity to consider how different strategies within, and emphasis between, these pillars affect the plausibility and cost of deep decarbonization.

Energy efficiency and conservation

Energy efficiency means providing the same energy service (e.g. hot water, mobility, lighting) with less input energy required. Energy efficiency is both an important measure from the perspective of both emissions reductions and cost. Less energy efficiency means that a larger quantity of more expensive measures will be needed, increasing the societal cost of deep decarbonization. Conservation is a change in behavior to reduce energy demands. For example, bicycling or walking rather than driving. The scenarios we use in this study focus on energy efficiency and assume only a very small amount of conservation.

Electrification

Electrification strategies shift energy usage from on-site combustion of fossil fuels in vehicles and buildings to power from the electric grid. Electrification can be an effective emissions reduction strategy because of the relatively high efficiency of electric end-uses and the complementarity with efforts to decarbonize the electric sector. However, some electrification measures are more cost effective than others, so like other emission reduction opportunities, electrification must be used strategically. An important consideration when evaluating the costs of electrification are the potential impacts to the electric system’s peak demand and associated infrastructure costs.

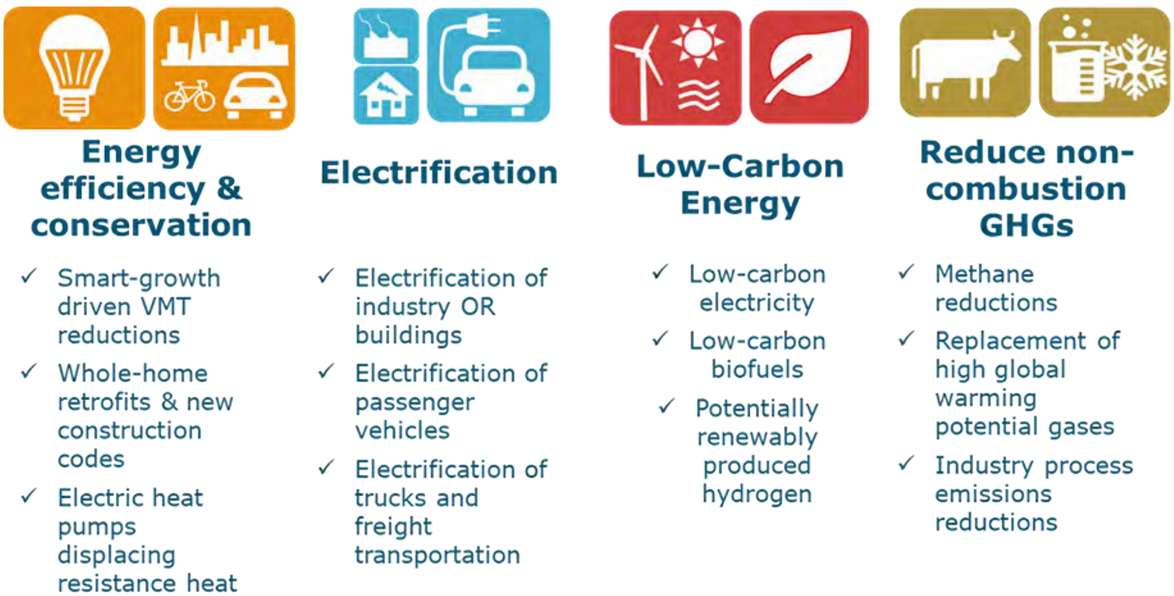
Low-Carbon Energy

Low carbon energy strategies substitute fossil fuels like gasoline, diesel, coal, and natural gas with low emission alternatives like renewable electricity, renewable natural gas and biodiesel. The advantage of low-carbon energy is that they can be formulated as a 'drop in' fuel and used in existing equipment with little modification. For example, biodiesel used in trucking. However, the available supply of sustainable biofuels is limited, falling far short of existing demands for liquid and gaseous fossil fuels in the Northwest, and the costs are higher than the fossil-fuel they replace. Therefore, the limited supply of sustainable biofuel resources must be used strategically, targeted to where they provide the highest value.

Reduction in non-combustion emissions

Non-combustion emissions include several different greenhouse gasses that are released or generated via non-combustion processes. Some non-energy emissions are produced through biogenic processes (e.g. urban wastes or manure), others occur because of industrial processes, while some are the result of the extraction or transportation of fossil fuels. Non-energy emissions often come in the form of greenhouse gasses with high global warming potential like methane or nitrous oxide. Strategies that reduce these emissions are important components of economy-wide decarbonization.

Figure 8: Pillars of Deep Decarbonization[4]



1.2.2 PRIOR DEEP DECARBONIZATION STUDIES AND ANALYSES OF "PEAK HEAT" NEEDS

While there is support for decarbonization in the Northwest, many questions remain about how to achieve this transformation of the region's energy economy. Several existing studies have evaluated different scenarios to achieve an 80% reduction in greenhouse gas emissions:

+ In 2014, the "Pathways to Deep Decarbonization in the United States" published by E3, in collaboration with Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory, evaluated scenarios with different electricity generation mixes, including renewables, nuclear power, and carbon capture and sequestration. In that study, the Pacific Northwest was

[4] VMT = vehicle miles traveled

grouped with the broader U.S. census region for the Pacific, including Alaska, Washington, Oregon, California, and Hawai'i.

- In 2016, the Obama White House published the "United States Mid-Century Strategy for Deep Decarbonization" evaluating several scenarios with a focus on the role of carbon sinks and carbon dioxide removal technologies in achieving the 2050 GHG goal.
- In 2017, the Office of Governor Inslee published a study evaluating decarbonization options for Washington State, and in 2018, Portland General Electric (PGE) published decarbonization scenarios for their service territory. Both the Washington state and PGE studies were performed by Evolved Energy and evaluated high building electrification scenarios and scenarios without building electrification.

However, none of these prior studies, to our knowledge, have investigated the costs and implications of reliably meeting winter peak energy needs during the coldest days experienced in the region. This study evaluates the cost implications of serving winter peak heating needs in the context of achieving an 80 percent reduction in GHGs by 2050.

In addition, this study evaluates the potential role and impact of natural gas heat pumps, an emerging technology which has not been evaluated in prior deep decarbonization studies, to our knowledge. Finally, a wide range of electric heat pump performance and cost assumptions are considered, reflecting some of the uncertainties in both technology innovation and regionally-specific building retrofit and installation costs. Prior studies appear to have relied primarily on national cost estimates and have not explicitly accounted for heat pump performance characteristics with changes in temperature.

1.2.2.1 Peak heat needs

This study focuses in particular on the capacity needs to serve space heating loads and builds on an emerging area of research that is evaluating incremental peak loads if natural gas heating load converted to electricity using air-source heat pumps for space heating and water heating. Though the electricity system in the Northwest is currently winter peaking, the natural gas system in the region provides the bulk of peak-space heating energy. NW Natural estimates that electrifying winter peak natural gas heating loads would increase the region's peak by nearly 30 GW (Northwest Natural 2017). Other utilities and researchers in the Northwest have also begun to examine this issue. For instance, Avista estimates that electrifying its gas loads would increase electric peak in its service territory by over 1,600 average megawatts (aMW) per day, just short of its current peak load of 1,681 aMW per day (Avista 2018). The Northwest Power and Conservation Council estimates that a high electrification case for the region could lead to a winter peak of over 65 GW, an 85% increase over today (Jourabchi 2018).

These regional findings are consistent with findings elsewhere in the world. Researchers at the University of Central London find that that the electric sector peak would more than double under large-scale deployment of electric heat pumps in the United Kingdom (Strbac et al 2018). Indeed, 'heat decarbonization' has been an ongoing policy and research question in the United Kingdom, with a variety of analyses examining the infrastructure implications of reducing emissions in buildings (Howard and Bengherbi 2016, MacLean et al 2016). These studies consider the heat required not only in average conditions, but also in peak conditions, usually defined as a historical '1 in 10' or '1 in 20' heating event. A key take-away from the existing literature on decarbonizing heat, both in and outside the Northwest, is the importance of accounting for peak conditions.

1.2.3 STUDY GOALS AND QUESTIONS

This study seeks to evaluate deep decarbonization strategies in buildings, within the context of an economy-wide pathway to 2050. This study evaluates scenarios that achieve the 2050 climate goal while continuing to rely on the region's existing gas distribution system, and scenarios that switch to a reliance on electric heat pumps for space and water heating. The scenarios that continue to rely on the direct use of natural gas blend low-carbon fuels into the gas pipeline, including renewable natural gas and in one case, renewably produced hydrogen. The electrification scenarios evaluate the implications of serving peak heat needs with electric heat pumps, together with a broader economy-wide evaluation of greenhouse gas mitigation options and costs. Furthermore, these scenarios seek to balance a reasonable set of GHG mitigation measures across sectors, avoiding the most expensive mitigation options where possible.

The key research questions include:

+ What are viable pathways to achieve deep decarbonization in the Northwest, focusing on different strategies in buildings?
+ How can NW Natural, and the natural gas system, contribute towards achieving the region's GHG goals?
+ What are the potential electric load impacts of electrifying buildings in the region?
+ What key factors affect the cost of different decarbonization strategies?

2 Study Approach

This report builds on prior deep decarbonization analyses from other regions and other states but uses an expanded analytical toolkit to draw out the implications of different decarbonization strategies, with a focus on the role of the buildings sector in achieving an economy-wide emissions reduction goal.

The core analytical tool used to evaluate long-term carbon reduction scenarios is an economy-wide energy and emissions accounting model developed by E3 called PATHWAYS. This model ensures that the long-term scenarios evaluated all achieve the economy-wide 2050 GHG emissions constraint. The Northwest version of the PATHWAYS model is tailored to region specific energy demands, supply and technology stocks, using local data whenever possible. The tool is also benchmarked to the existing Oregon and Washington state greenhouse gas emissions inventories.

PATHWAYS is an economic energy and greenhouse gas emissions accounting tool. A key feature of the PATHWAYS model is its detailed treatment of the Northwest's energy infrastructure. Energy infrastructure includes, but is not limited to, power plants, industrial facilities, trucks, cars, buses and building end use equipment. Each type of infrastructure consumes energy to meet projected energy services demands for the regions needs including transportation, heating, cooling, lighting, industry, agriculture and other uses spanning the entire energy system. Depending on the equipment stock, its fuel, and its efficiency this energy use results in different fuel consumption, emissions, and costs for the region.

Within this framework, there are three key areas that receive more detailed analysis: 1) Biofuels supply and costs, 2) Building performance, and 3) the Electricity sector, as described in more detail below.

+ **Biofuels supply and costs:** Carbon-neutral biofuels are a key strategy to reduce greenhouse gas emissions in the scenarios evaluated here. However, the sustainable biomass feedstocks that are needed to produce carbon-natural biofuels are also a fundamentally limited resource, and thus valuable. Examples include biogas from landfills, waste water treatment facilities or dairies, as well as wood from forestry plantations or waste wood. In order to evaluate the supply constraints and costs of producing sustainable biofuels, we augment the PATHWAYS model with a Biofuels Optimization Module. This tool accounts for the limited biofuel feedstocks and allocates them to final fuels to maximize emissions reductions at least cost.

+ **Building performance:** This study evaluates how the performance of electric air source heat pump space heating technologies might perform under a range of cold temperatures across the Pacific Northwest using a building simulation model, EnergyPlus. EnergyPlus estimates the hourly energy requirements of space heating in different building types across the region at different temperatures.

+ **The electricity sector:** In order to reflect the potential costs and carbon implications of decarbonizing the electricity sector we apply an electricity sector capacity expansion model called RESOLVE. This tool is designed to identify least-cost electricity generation portfolios under carbon constraints. The model includes historical hourly load shapes which are modified to reflect the impacts of scenario-based assumptions about energy efficiency and electrification in transportation, industry and buildings, to the extent applicable. After accounting for load diversity and building shell improvements, the hourly load shapes from the EnergyPlus building simulations are used to modify the base hourly load profiles in the RESOLVE model. This creates a more realistic picture of how hourly electricity demands, and winter peak electricity demands, could change under a high building electrification future.

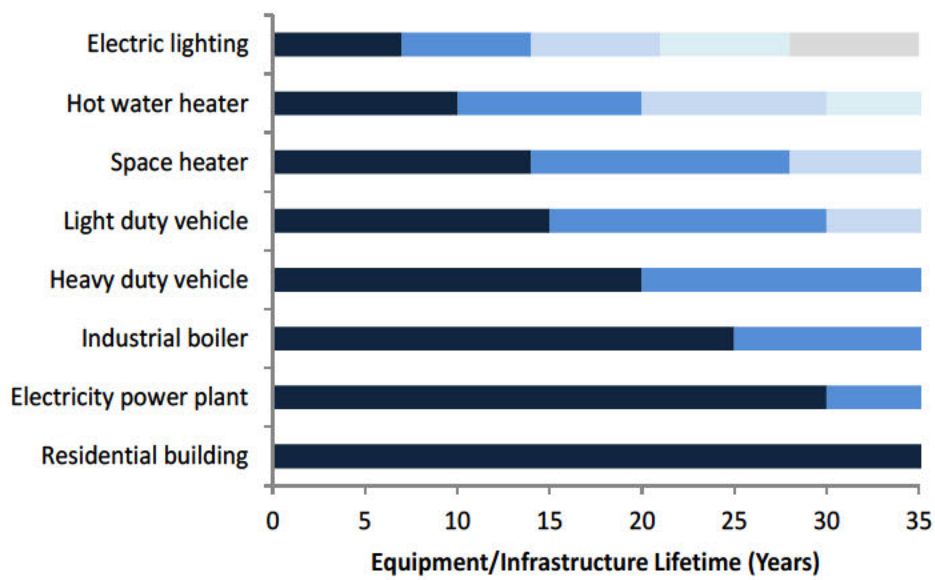
A list of key data sources used to develop this analysis can be found in the Appendix.

2.1 Economy-wide Energy and Emissions Scenarios

The core analytical tool used in this analysis is the Northwest PATHWAYS model. E3 first developed the PATHWAYS framework in 2008 to help policy-makers, policy implementers and businesses better understand plausible decarbonization scenarios. The model has since been modified and improved on over time in projects that analyze deep decarbonization at the national level, in several states, as well as sub-state jurisdictions.

A key feature of the PATHWAYS model is its detailed treatment of the Northwest's energy infrastructure. Energy infrastructure includes, but is not limited to, power plants, industrial facilities, trucks, cars, buses and home equipment. Each type of infrastructure consumes energy and produces emissions differently, but collectively they determine the direction of the region's emissions trajectory. Many of these technologies are long-lived. For instance, a home built today will likely still be in use by mid-century. Because investments made in the near-term shape the energy system of the future, the PATHWAYS model includes a detailed, bottom-up stock accounting treatment of the region's energy infrastructure on a technology-specific level (Figure 9). By accounting for vehicle and equipment lifetimes, PATHWAYS identifies the pace of change necessary to deploy decarbonization strategies while avoiding costly early retirement, and captures potential path dependencies of near-term decisions.

Figure 9: Infrastructure lifetimes in PATHWAYS



A second key feature of the PATHWAYS model is its ability to link sectors. By linking sectors, PATHWAYS identifies where aggressive action in one sector can enable emissions reductions elsewhere in the economy. For instance, the detailed treatment of the electricity sector is explicitly tied to the carbon savings associated with electric vehicles.

Demands for energy in PATHWAYS are driven by forecasts of population, building square footage, vehicle miles traveled, and other drivers of energy services. The rate and type of technology adoption and energy supply resources are all user-defined scenario inputs. PATHWAYS calculates energy demand, greenhouse gas emissions, the portfolio of technology stocks in selected sectors, as well as capital costs and fuel costs for each year between 2015 and 2050.

2.2 Biofuels Supply and Costs

Sustainable Biomass and Biofuel Resource Availability

The availability of carbon-neutral biofuels as a GHG reduction option is limited by the supply of sustainable biomass feedstocks. The United States Department of Energy's 2016 Billion Ton Study (BTS) estimates the supply of biomass feedstocks by county and by type, at different price points (USDOE 2016). The DOE BTS study also estimates the potential supply of both biomass wastes and residues, as well as purpose grown crops such as plantation forests, switchgrass and miscanthus. This analysis assumes a transition away from current, food-based biofuel feedstocks such as corn and soy, and towards a more advanced and sustainable supply of biofuels. In addition to the U.S. DOE BTS study, NW Natural provided additional estimates of the resource potential for regional biogas supplies from landfills, waste water treatment facilities and other sources of biogas that are not well represented in the BTS data set, based on U.S. EPA data and a Washington

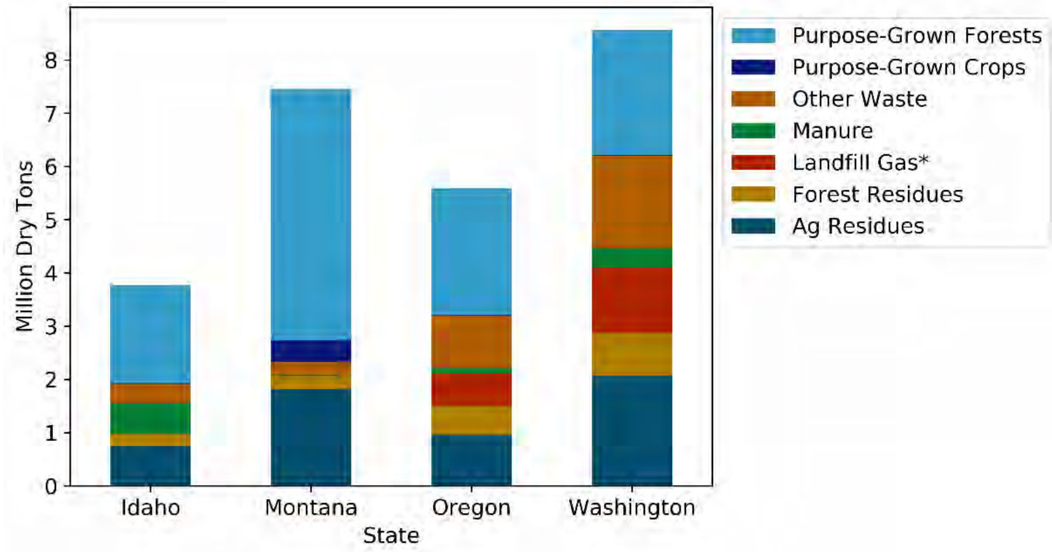
State University Energy Program study.[5] This data was reconciled with the DOE BTS study by adding 27 TBtu of biomethane potential from landfill gas and wastewater treatment plants and 0.14 million dry tons of manure feedstock.

In this study, we assume that biomass used to produce carbon-neutral biofuels are limited to wastes, residues and purpose-grown energy crops within the regional Northwest: Idaho, Montana, Oregon and Washington. We also assume that Oregon and Washington have access to their population share of the four-state region (80.7%). This represents a moderate quantity of biofuels compared to alternative approaches, resulting in a total of 25 million dry tons of biomass supply available to Oregon and Washington (Figure 10). This is in contrast to Washington State's deep decarbonization study which assumed 23.8 million dry tons available to the state. The Portland General Electric Pathways to Deep Decarbonization study also assumed a larger per capita share of biomass for biofuels compared to this study. Applying the PGE study methodology to the Oregon and Washington region would result in an assumption of 46.7 million dry tons of biomass available to the region, almost double the amount available in this study.[6]

[5] Oregon landfill gas data was based on the U.S. EPA Landfill Methane Outreach Program (LMOP) database. Washington data on biogas feedstocks was based on the Energy RNG Roadmap for Washington (Washington State University Energy Program 2017).

[6] PGE's share of the U.S. biomass supply is assumed to be 7.3 million dry tons (MDT), which is equal to the U.S. supply of biomass of 1,300 MDT multiplied by the region's population share (1.8 million people in PGE/320.9 million people in the U.S.). Applying this same method to Oregon and Washington would result in 46.7 MDT: 1,300 MDT of biomass supply in the U.S., multiplied by the region's population share (11.5 million people in Oregon and Washington/320.9 million people in the U.S.). See: **https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning**

Figure 10. Biomass feedstock supply by type, 2050



*Tons of landfill gas are weighted by a factor of 3 to account for the approximate relative energy yield.

Biofuels Costs and Supply

The E3 PATHWAYS Biofuels Module generates supply curves that determine the availability and cost of renewable liquid and gaseous biofuels. The model optimizes the selection of feedstocks, conversion pathways, and final fuels. The optimization is flexible and can be configured to select a least-cost portfolio given final fuel demands, maximum carbon abatement given available feedstock, or some combination of these and other policy drivers. When multiple conversion pathways are available for a given feedstock and fuel pairing (for instance, pyrolysis vs. Fischer Tropsch for conversion of wood to diesel), the selection criterion is also flexible: the model can be configured to choose either the cheapest conversion process or the one with the highest yield.

E3's biofuels conversion pathway assumptions are drawn from work done as part of a California Energy Commission grant (E3, 2018). E3 worked with a combination of published literature and external expert consultations to develop estimates of conversion efficiencies and costs, assuming biofuels can be produced more cheaply in the future through industry learning.

2.3 Building Performance

EnergyPlus is a building energy simulation model that models energy consumption for heating, cooling, ventilation, lighting and plug loads in both residential and commercial buildings. E3 worked with Big Ladder Software (Big Ladder) to develop a set of building simulations to identify the hourly load impacts of electric space-heating.[7] Big Ladder simulated four building types: a small single-family home, a large single-family home, a multi-family building and a small commercial building. Each building type included two vintages (older and new construction) and two climate zones (West of the Cascades, represented by Portland, OR and East of the Cascades, represented by Spokane, WA), both of which determine building performance. Three different heating technologies were simulated in each building: an electric resistance heater, an air-source electric heat pump and a cold-climate air-source heat pump. Table 1 lists the different parameters simulated in this analysis.

[7] The hourly usage of natural gas equipment was not modeled in EnergyPlus since the peak impact of natural gas equipment is relatively simple to estimate.

Table 2: Building simulation parameters

Building types	Vintages	Climate zones	Heating technology
• Small single-family • Large single-family • Multi-family • Commercial	• Existing (built in 1990) • New (Most recent building energy codes)	• West of Cascades (Portland) • East of Cascades (Spokane)	• Electric heat pump • Cold climate electric heat pump • Electric resistance

Weather assumptions

In order to capture the inter-year variation in peak heating requirements in buildings, NW Natural worked with E3 to develop a range of temperature conditions for the building simulations. Building usage was simulated using weather data for Portland and Spokane[8] so that the resulting annual energy demands are representative of normal weather conditions. However, this representative weather data was supplemented with an imposed a 3-day cold-snap representing a 1- in 10 year cold event.[9] This represents a more extreme, but still within the historical experience, heating event for the region. The average minimum 7am temperature in a given year in NW Natural's service territory over the last decade was 18° Fahrenheit (F), while the '1 in 10' year cold-snap included in the weather used in this study dips to 10° F. This 10° F cold-snap event represents a heuristic for the types of inter-year variation in heating needs that could be experienced by buildings across the region.[10]

[8] Weather from 2012 was found to be representative, so the hourly weather from 2012 was used as an input to the simulation.
[9] Using the methodology in NW Natural's 2018 IRP, a 1-in 10 year cold event in Portland includes a day with an average temperature of 17.09°F. Consequently, the hourly temperature profile from the December 7 through December 9, 2013 cold event was added to the data to represent a 1-in 10 year event. The average temperature of the coldest day of this cold event (December 8th, 2013) was 17.42°F.
[10] Note that these figures for Portland are representative and adjustments were made to account for regional diversity in weather conditions.. See Section 6.4 in the appendix for more information on the treatment of weather.

2.4 Electricity Sector

In order to simulate the costs and performance of the electric grid under a very low-carbon future, this study uses a tool called RESOLVE. This tool is an electricity-sector resource investment model that uses linear programming to identify optimal, long-term generation and transmission investments, subject to reliability, technical, and policy constraints. RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost electric sector investment plan, accounting for both upfront capital costs and variable costs to operate the grid. This project uses a Northwest specific version of RESOLVE first developed for the Public Generating Pool in 2017 (E3 2017).

RESOLVE selects from a wide range of potential new generation resources. The options for new investments considered in this study are limited to those technologies that are commercially available in the Pacific Northwest today. New nuclear power and carbon capture and sequestration are not considered in these scenarios.

RESOLVE includes a variety of Northwest specific inputs, including hydro dispatch informed by historical operations. RESOLVE captures the constraints on the dispatch of the hydroelectric system by deriving constraints from actual operational data. Three types of constraints govern the operation of the hydro fleet as a whole: 1) daily energy budgets, 2) maximum and minimum hydro-electric generation levels and 3) maximum multi-hour ramp rates. Collectively, these constraints limit the generation of the hydro fleet to reflect seasonal limits on water availability, downstream flow requirements, and non-power factors that impact the operations of the hydro system. RESOLVE incorporates a number of other constraints including a planning reserve margin (PRM) that requires a minimum quantity of firm capacity, and the ability to impose a GHG cap on electricity emissions over time.

RESOLVE is a complementary model to both PATHWAYS and EnergyPlus. PATHWAYS identifies the annual electric loads that the electric sector must serve and the emissions budget that constrains RESOLVE's capacity expansion and operational linear optimization problem. EnergyPlus provides hourly load shapes for individual buildings, that when aggregated and diversified, can be used to inform changes to the system-level building load shape, which determine both the annual peak capacity requirements in RESOLVE and operational requirements of the electric system.

3 Northwest PATHWAYS Scenarios

PATHWAYS is a user-defined scenario analysis framework. Scenarios are not forecasts. They do not represent an expectation of what a future energy system will look like. Nor are they mere speculation. Instead, scenarios are opportunities to ask "what if?" questions about plausible decarbonization trajectories for Oregon and Washington. This scenario analysis approach is meant to draw out potential implications and trade-offs between different approaches to achieve deep decarbonization.

3.1 Scenario Design

This analysis develops four decarbonization scenarios that examine trade-offs between and within different strategies for providing heat in buildings, as well as a Reference scenario, representing a "current policy" trajectory. The tradeoffs between building heating strategies in the decarbonization scenarios have implications for the rest of the economy as well as total scenario costs, since all scenarios are constrained to meet the same long-term carbon reduction goal.

Four variations of building heating equipment are considered: gas furnaces, electric air-source heat pumps, gas-powered heat pumps and cold-climate air source heat pumps. These four scenarios can be binned into two scenario categories: Direct Use Gas Scenarios and Electric Heat Pump Scenarios.

3.1.1 REFERENCE SCENARIO

The PATHWAYS Reference scenarios is a representation of current policy in the Northwest as of Summer 2018. Key policies include the Oregon Clean Fuels Program, Oregon's participation as a ZEV State, a 20%

regional RPS target by 2045,[11] and energy efficiency savings consistent with the Northwest Power and Conservation Council's 7th Power Plan.

3.1.2 DIRECT USE GAS SCENARIOS

In these scenarios the gas distribution pipeline system continues to provide heat to residential and commercial buildings in the Northwest. The proportion of homes in Oregon and Washington that are served by gas are held constant through time, though the total number of gas homes increases as the region's population expands. In each of the Direct Use Gas Scenarios, natural gas is blended with renewable gases like biomethane and hydrogen to decrease the carbon content of energy provided via the existing pipeline infrastructure.

3.1.2.1 Gas Furnace Scenario

In the Gas Furnace Scenario, the primary heating equipment in homes transitions to high efficiency versions of gas furnaces and water heaters, both of which are commonly used technologies today. By 2030, nearly all gas space-heaters sold are 98% efficient condensing gas furnaces while air conditioning needs continue to be met with high efficiency air conditioners.

3.1.2.2 Gas Heat Pump Scenario

In the Gas Heat Pump scenario, natural gas fired air-source heat pumps, an emerging technology, are assumed to become the primary space heating and water heating equipment in buildings that typically use natural gas today. Gas heat pumps operate similarly to electric heat pumps, except that they are powered by gas rather than electricity. The Northwest Energy Efficiency Alliance (NEEA) is working to commercialize gas heat pumps in the region and provided E3 with estimates of the performance

[11] This is a regional weighted figure representing the combination of the 50% RPS by 2040 in Oregon and the 15% RPS by 2020 in Washington.

characteristics and potential costs of natural gas heat pumps. Gas heat pumps have improved efficiencies compared to gas furnaces, achieving a coefficient of performance (COP) of 1.4 for space-heating and 1.3 for water-heating. NEEA believes natural gas heat pumps may be well suited to provide both space- and water-heating in a combined unit, which could lead to cost savings relative to the cost of an individual water heater and gas heat pump heater.

3.1.3 ELECTRIC HEAT PUMP SCENARIOS

The electric heat pump scenarios examine futures where the bulk of heat in buildings is provided by electric air-source heat pump space heaters and water heaters. Electrification paired with a 95% decarbonized electric sector achieves a near-complete decarbonization of heat in buildings.

3.1.3.1 Electric Heat Pump Scenario

This scenario replaces both existing gas and electric technologies with a high efficiency (HSPF 9) electric air-source heat pump for space heating, representing an efficiency option that is readily available today. [12] This scenario does not assume installations of higher efficiency systems on the upper-end of the heat pump market, nor does it assume any technology innovation. An HSPF 9 heat pump system is relatively efficient in terms of annual energy but becomes less efficient at cold temperatures. At 34°F these heat pump systems "lock-out" and switch to the use of electric resistance back-up heat.[13] This scenario represents a future where the region proceeds with building electrification using a commonly-available

[12] Heating Season Performance Factor, or HSPF, is a measure of the seasonal efficiency of heat pump equipment in the winter. The Federal minimum for air source heat pumps is an HSPF rating of 7.7. In Oregon, to qualify for an Oregon residential energy tax credit, a ducted air source heat pump system must have an efficiency of 9.5 HSPF or greater. The Energy Trust of Oregon offers incentives for systems that have an HSPF of 8.5 or higher. High efficiency mini-split heat pumps may have an HSPF efficiency rating of 12.5 but may not be suitable in larger homes or some applications.

[13] Energy Trust of Oregon provides an incentive to set a compressor lock-out temperature to 35°F (or "as close as possible"). High efficiency mini-split heat pumps do not "lock-out" at temperatures experienced in the Pacific Northwest but may not be suitable in larger homes or some applications.

heat pump technology and common HVAC installation procedures without accounting for the system-wide peak impacts of electrification.

3.1.3.2 Cold-Climate Electric Heat Pump Scenario

Cold-climate air-source heat pumps are commercially available products, though still relatively uncommon in today's market, that perform better at cold temperatures than more common heat pumps. Their improved performance at cold temperatures is due to their having an inverter driven, variable-speed compressor, and more advanced control systems. The Northeast Energy Efficiency Partnerships (NEEP) has established a product specification for cold-climate heat pumps and provides a listing of systems that meet that specification. To qualify, a system must have a variable speed compressor, a coefficient of performance (COP) at 5° F higher than 1.75, and an HSPF of at least 10.

For this analysis, Big Ladder simulated a ducted cold-climate heat pump with an HSPF of 10.5. The system uses supplemental heat once the temperature drops below 20° F.[14] Below that temperature, the heat pump can still provide a portion of the heat, with electric resistance heating providing the additional heat needed to maintain building comfort. Note that we did not model the hourly performance of ductless heat pumps in this study, assuming that homes that fuel-switch from natural gas to electric heating would already have duct-work. We do assume for costing purposes only that ductless heat pumps are installed in homes that currently have electric resistance heat.

[14] For comparison with NEEP's cold-climate heat pump specifications the modeled system has a COP of 2 at 5°F.

3.2 Common Scenario Assumptions

The scenarios in this analysis examine different strategies to deliver heat in buildings while achieving the same level of economy-wide carbon reduction. However, there are many shared features and common assumptions across the scenarios, which are described below:

- **Energy efficiency and conservation**: High levels of energy efficiency and conservation in buildings and industry are critical to reduce energy demands and save carbon in all scenarios. In all scenarios, ductless heat pumps replace nearly every electric resistance heater in buildings, while deep building shell retrofits reduce the heat required in residential and commercial buildings, and smart-growth measures decrease per-capita vehicle-miles travelled in the region.
- **Electrification in transportation, and industry OR buildings**: All scenarios assume nearly complete electrification of passenger vehicles, trucks and off-road vehicles by 2050. The amount of electrification in industry and buildings varies by scenario, as discussed in more detail below.
- **Low carbon fuels: biofuels and renewable natural gas:** All scenarios include renewable natural gas and renewable jet fuel to decarbonize fuels that may be otherwise difficult to electrify. The total quantity of biofuels varies between scenarios, ranging from 73% of the available biofuel supply in the Electrification scenarios, to 97% to 100% of the available supply in the Direct Use of Natural Gas scenarios.
- **Low-carbon electricity:** All scenarios assume nearly complete decarbonization of the electricity sector through expanded reliance on renewable generation, and continued reliance on hydropower and nuclear energy, achieving between 95% and 97% zero-carbon electricity generation by 2050. All of the scenarios consider additional demand response, electricity storage, wind, and solar generation, but do not consider the development of carbon capture and sequestration, new nuclear power, or new large-scale hydropower as zero-carbon technology options. In all scenarios, the electricity sector is allocated a carbon budget that allows the overall scenario to meet the 2050 carbon reduction goal.
- **Reductions in non-combustion GHG emissions**: Each scenario assumes concerted efforts to reduce non-combustion emissions, achieving approximately a 53% reduction in non-combustion

emissions by 2050, relative to 1990 levels. This means that a higher share of reductions is required in the energy sector, in order to achieve an economy-wide goal of 80% below 1990 levels by 2050. Methane emissions from manure, landfills and wastewater are captured in each scenario and converted to biomethane. Fluorinated (F)-gases are replaced with lower cost refrigerants throughout the economy. The scenarios also assume efforts to reduce fugitive and process emissions in industry.

All of these common mitigation assumptions represent major shifts from a business-as-usual world.

3.3 Key Differences between the Scenarios

The different building strategies applied in each scenario result in different implications for other sectors of the economy. These differences are summarized by sector, and in the table below:

- **Electrification in Industry:** The Direct Use Gas Scenarios assume that 30% of industrial energy demand currently served by other fuels is electrified by 2050. This quantity of electrification is consistent with a near-complete electrification of industrial HVAC equipment, as well as high levels of process heating and boiler electrification. No industrial electrification is assumed in the Electric Heat Pump Scenarios, beyond a limited switching of HVAC electricity demand to electric heat pumps.
- **Electrification in Buildings:** As discussed above, the Direct Use Gas Scenarios do not assume any new building electrification, beyond the current market share of electric heat in existing buildings in the Pacific Northwest. Buildings with existing electric resistance space heating are assumed to switch to electric heat pumps in all scenarios. In the Electric Heat Pump Scenarios, 90% of all buildings are assumed to use electric heat pumps for space heating and water heating by 2050. This assumes a rapid transition towards electric heat pump adoption in both new construction and existing buildings, requiring major retrofits of existing space and water heating equipment.
- **Low Carbon Fuels: Biomethane and Renewable Hydrogen:** All of the scenarios include substantial use of carbon-neutral, advanced biofuels to achieve the 2050 GHG targets. In the Direct Use of

Natural Gas Scenarios, up to 25% biomethane is blended into the natural gas pipeline by 2050, based on the assumed available regional supply of sustainable biomass. This is equivalent to 72 TBtu of renewable natural gas by 2050 in the Gas Heat Pump Scenario, and 84 TBtu of renewable natural gas in the Gas Furnace Scenario. The total quantity is higher in the Gas Furnace Scenario because the total gas demand is higher in this scenario. In the Gas Furnace scenario, an additional 6.5% of the energy in the gas pipeline is provided by renewably-produced hydrogen from electrolysis.

+ **Zero-Carbon Electricity:** In all scenarios, electricity is nearly decarbonized by 2050. The Electric Heat Pump scenarios assume that 95% of electricity generation is provided by zero-carbon resources, mostly from renewable energy and hydro-power by 2050. This is equivalent to a 5 MMtCO2 carbon budget in 2050 for the electric sector. The Direct Use Natural Gas Scenarios assume that 97% of electricity generation is provided by zero-carbon resources by 2050, equivalent to a 3 MMtCO2 carbon budget for the electricity sector.

These key scenario design differences are illustrated in Table 3.

Table 3. Key assumptions by scenario

2050 metrics	Gas Furnace Scenario	Gas Heat Pump Scenario	Electric Heat Pump Scenario	Cold-Climate Heat Pump Scenario
Share of Natural Gas Space and Water Heating Electrified (fuel switching)	0%	0%	96%	96%
Industry Electrification (fuel switching, % total industry energy demand)	30%	30%	5%	5%
Carbon Free Electricity Generation	97%	97%	95%	95%
Biofuel Development (Share of available resource)	100%	97%	73%	73%
Hydrogen Mix in Gas Pipeline	7%	0%	0%	0%

4 Results

In all four PATHWAYS scenarios, achieving deep decarbonization will require transformative change to the energy economy of the Northwest in just over 30 years. This is a relatively short period of time compared to the investment decision timeframe and average lifetimes of energy infrastructure and equipment. A low-carbon energy transition for the Northwest region will only occur if investment decisions shift towards prioritizing higher efficiency options, and the development and use of low-carbon fuels. Those investment decisions range from small choices, like consumer purchases of LED light-bulbs, to large capital investment decisions by industrial facilities in the region.

4.1 Greenhouse Gas Emissions in a Low Carbon Future

Each scenario achieves the same 80% below 1990 target emissions budget of 29.3 MMtCO2 in 2050 and have very similar emissions trajectories over time. However, by 2050 the scenarios diverge in the allocation of emissions between sectors of the economy (Figure 11). The Gas Scenarios leave a larger share of the economy-wide budget to the buildings sector while the Electric Heat Pump Scenarios allocate more of the emissions budget to electricity and industry (Figure 12). The bulk of remaining energy emissions in both cases come from natural gas combustion, though the scenarios differ in where that gas is used. The Gas Scenarios rely more on direct-use of natural gas, while the Electric Heat Pump Scenarios use relatively more gas in the electricity sector, although the total use of natural gas is greatly reduced by 2050 in all scenarios relative to today.

Figure 11. Greenhouse Gas Emissions Over Time by Scenario and by Source in 2050

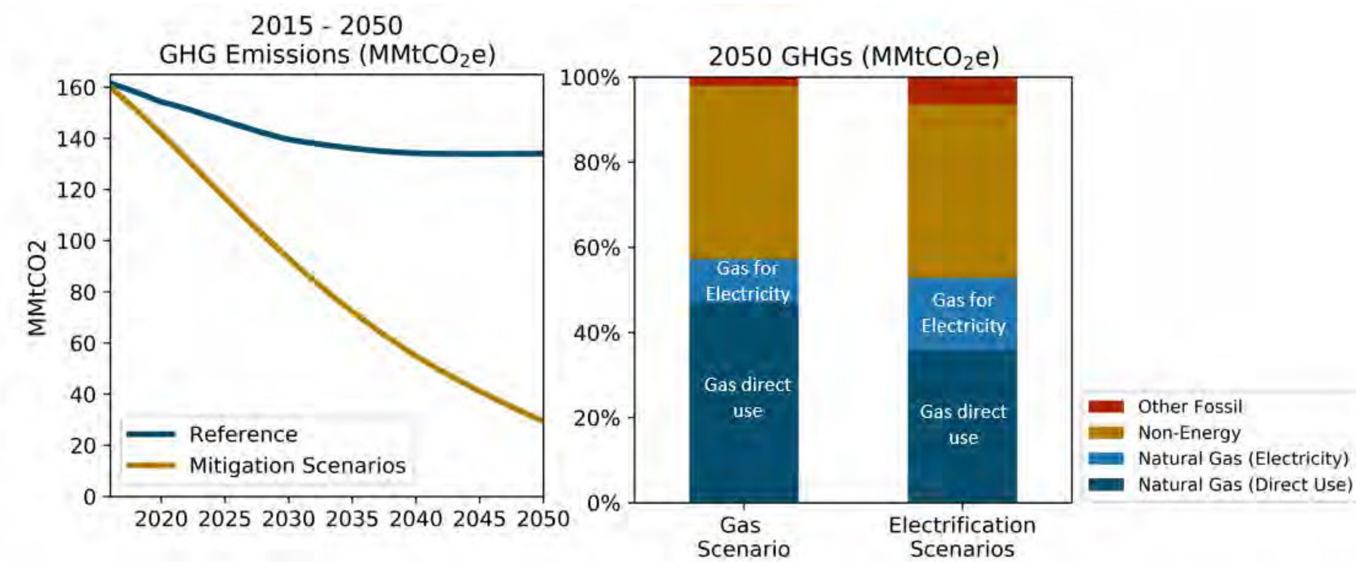
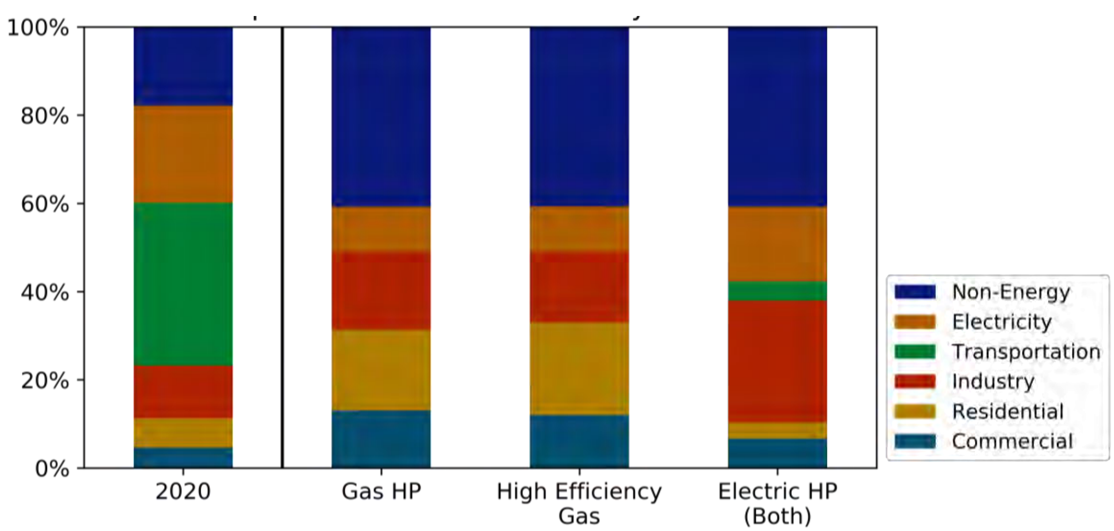


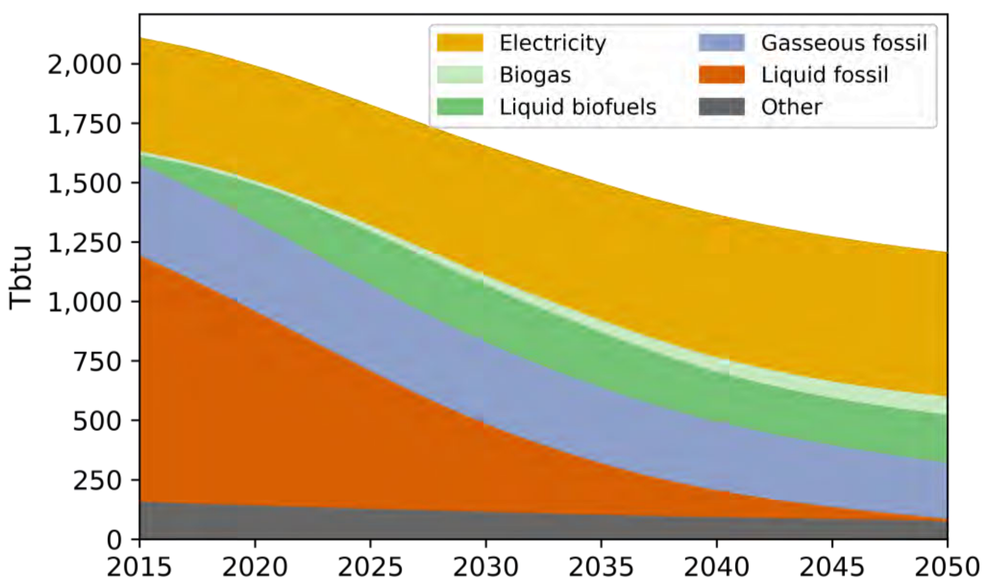
Figure 12. Share of Greenhouse Gas Emissions by Sector in 2020 and by Scenario in 2050



4.2 Energy Demand in a Low Carbon Future

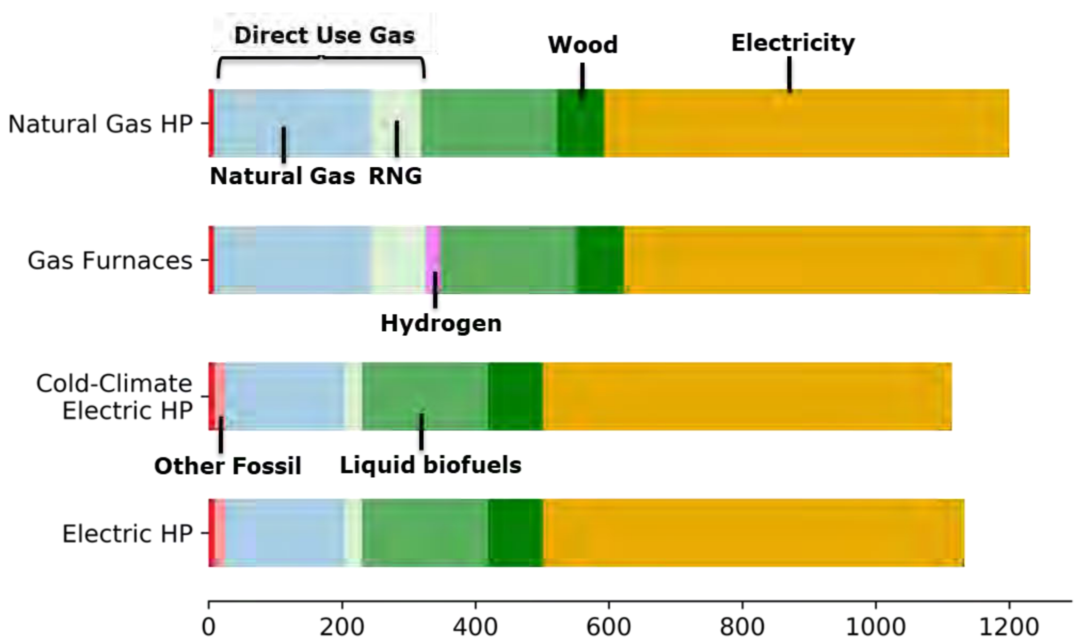
Delivered energy in the Northwest is dominated by the use of liquid fossil fuels (mostly gasoline and diesel in the transportation sector) and gaseous fossil fuels (mostly natural gas use in buildings and industry). Electricity is currently provided by a mix of coal, natural gas, hydropower, nuclear and renewables. In every mitigation scenario considered in this analysis, final energy demands are lower by 2050 than today, despite continued population and economic growth (Figure 13). The lower final energy demand is due to the combined impact of energy efficiency in all sectors (buildings, industry and transportation), as well as the efficiency savings from switching from internal combustion engines in vehicles (~20% efficient) to electric motor drive-trains in the transportation sector (~60% efficient).

Figure 13. Energy demand by fuel type, Gas Heat Pump Scenario



By 2050, low-carbon electricity is assumed to provide the largest share of final energy demands in all scenarios. The remaining liquid and gaseous fuels in the economy are blends of biofuels and conventional fossil fuels. Biofuels account for between 19% and 24% of final energy consumption in 2050 in all scenario. In the Gas Furnace Scenario, an additional 6% of pipeline gas energy comes from renewably-produced hydrogen (Figure 14).

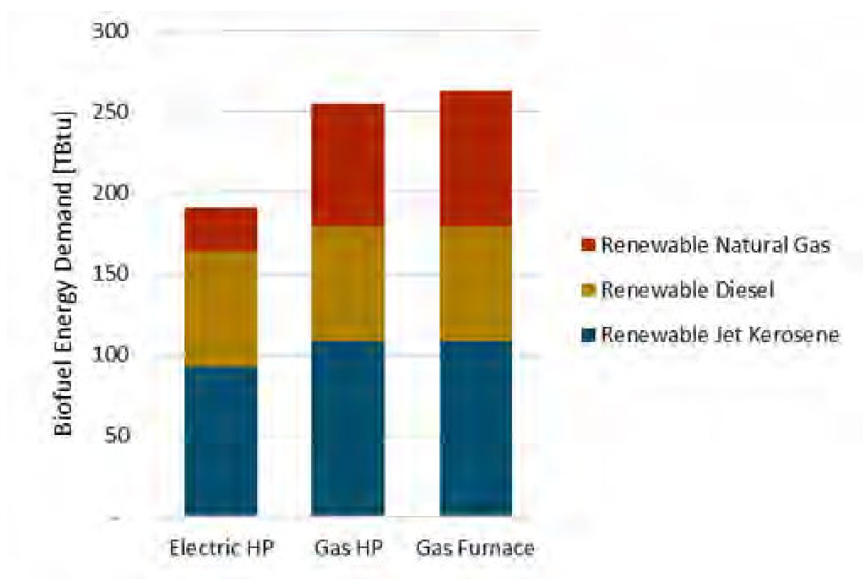
Figure 14. Final energy demand by fuel type and scenario, 2050 (Tbtu)



4.2.1 BIOFUELS

Carbon-neutral, advanced biofuels are a limited, but important, source of carbon reductions in all mitigation scenarios. The PATHWAYS biofuels module allocates biomass feedstocks to fuels, based on energy demands remaining after electrification and energy efficiency measures have been applied in each scenario. Most of the biomass is allocated to producing liquid fuels, largely renewable diesel and renewable jet kerosene to displace fossil fuel emissions in off-road transportation and aviation, both sectors which may be difficult to electrify (Figure 15). The allocation in these scenarios was selected by optimizing to maximize cost-effective GHG reduction from a societal perspective (e.g. consumer incentives and electric rate design options are not considered). For cellulosic and woody feedstocks, liquid fuels result in lower net cost CO_2 displacement than biomethane because of the high cost and CO_2 intensity of the displaced fossil fuels, but this result is sensitive to a number of uncertain model inputs, including projected biofuel conversion efficiencies. Biomethane is an important tool to decarbonize remaining pipeline gas in each scenario, with blends as high as 25% of total throughput in the Direct Use Natural Gas Scenarios. Biofuel demands are identical in both of the Electric Heat Pump Scenarios.

Figure 15. Biofuel Energy Use by Scenario, 2050



The PATHWAYS biofuels module determines a market-clearing price for biofuels on an economy-wide basis. The same market-clearing price for biofuels is assumed in all scenarios, based on an assumption that the market price will be set by regional, economy-wide supply and demand (Table 4).

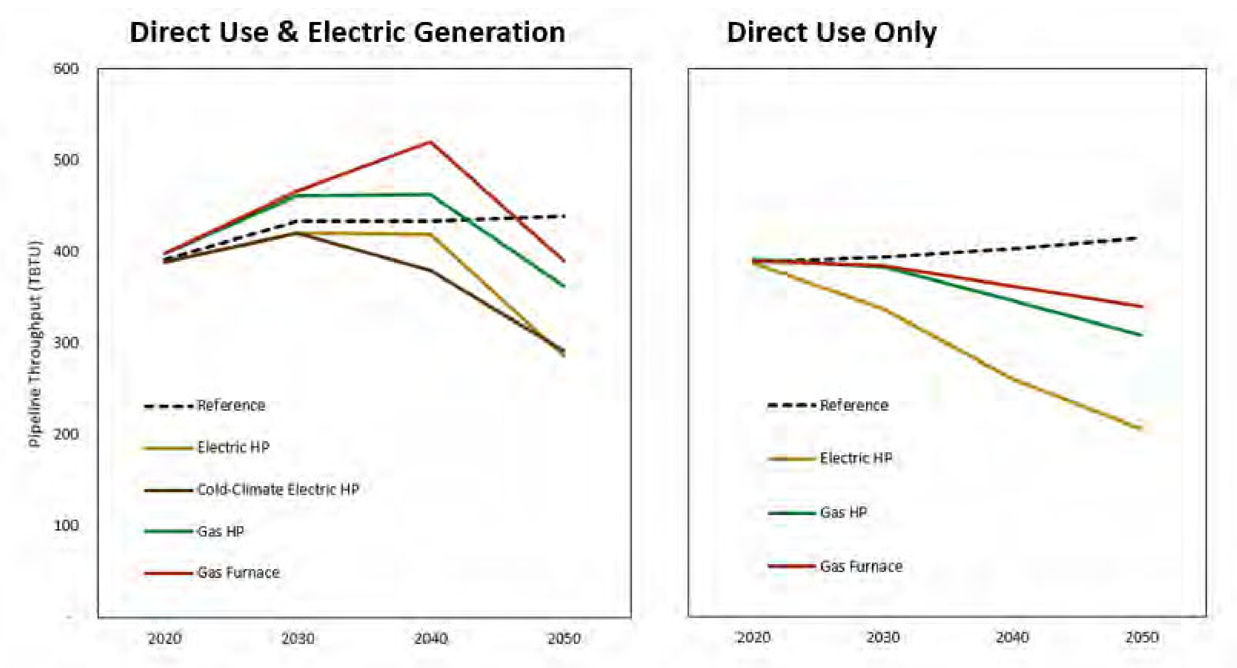
Table 4. 2050 estimated market clearing price for biofuels, by fuel type

Final biofuel	$ / MMBtu
Biomethane	$23
Renewable diesel	$51
Renewable jet kerosene	$49

4.2.2 DEMAND FOR PIPELINE GAS

Demand for natural gas decreases in every case relative to Reference (Figure 16). Direct use gas demand begins decreasing in 2020 due to aggressive energy efficiency in all cases. Further reductions in direct use gas occur in the Electric Heat Pump Scenarios as fuel-switching from gas to electric equipment in buildings occur. Total pipeline gas use in the region increases in the Gas Scenarios and is close to Reference in the Electric Heat Pump scenarios through 2040. This result is largely driven by a switch from coal-fired generation to natural gas combined cycle power plants. Later in the study period, the emissions cap for the electricity sector, achieved largely through additional renewable generation, leads to a sharp drop in gas use in the electricity sector between 2040 and 2050.

Figure 16: Pipeline gas throughput by scenario

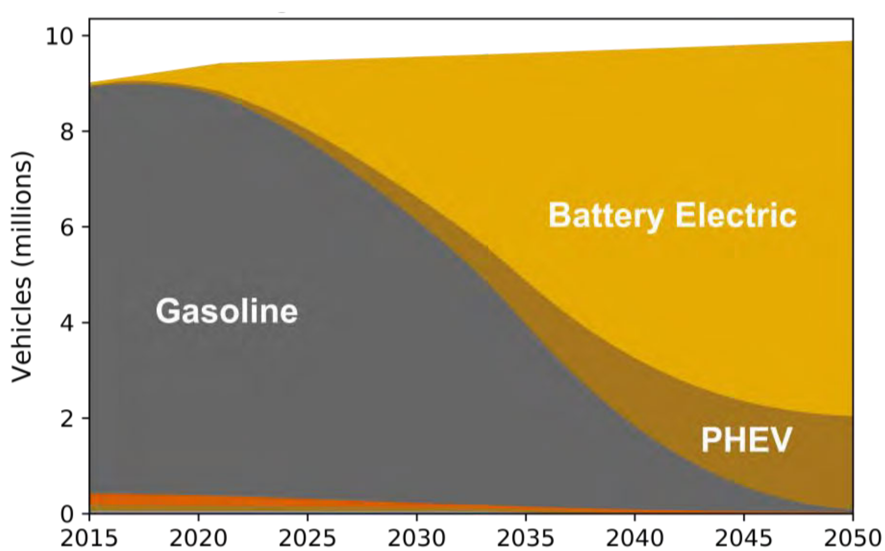


4.3 Transportation Sector

4.3.1 PASSENGER VEHICLES

Across all scenarios, passenger vehicle electrification is a core strategy to decarbonize the region's transportation sector, the largest source of GHG emissions in the Northwest region. In all scenarios, over 70% of passenger vehicle sales are from either battery electric or plug-in hybrid technologies in 2030, and by 2035, 100% of sales are either battery electric or plug-in hybrids. This translates to 3.4 million electric or plug-in electric passenger vehicles by 2030 and 9.8 million electric or plug-in electric vehicles by 2050 (Figure 17). Achieving this scale of light-duty vehicle electrification will require a complete transformation of consumers' vehicle purchase decision within the next two decades. In 2017, 2.5 percent of light-duty vehicle sales in Washington and 2.3 percent of sales in Oregon were battery electric or plug-in hybrid vehicles (Alliance of Auto Manufacturers 2018).

Figure 17. Millions of Passenger Cars and Trucks by Type, All Scenarios, 2015 – 2020



Barring a ban on fossil-fueled vehicles, consumer decisions will determine the pace of passenger vehicle electrification. Even under optimistic cost projections, electric vehicles are expected to be more expensive from an upfront cost perspective than fossil alternatives for at least the next decade (Bloomberg New Energy Finance 2018). This means that an increasing proportion of consumers will have to opt for vehicles with a higher upfront cost or will continue to require subsidies to drive ZEV sales.

Barriers to widespread adoption of electric vehicles must also be addressed, even as ZEVs move towards cost-parity with fossil alternatives. Non-cost considerations—for example, anxiety over range or the opportunity to refuel—may reduce consumers' propensity to adopt a new vehicle technology. Public charging infrastructure will be needed to address range anxiety concerns and ensure equitable access to electric vehicles for lower income drivers who may not have access to at home chargers.

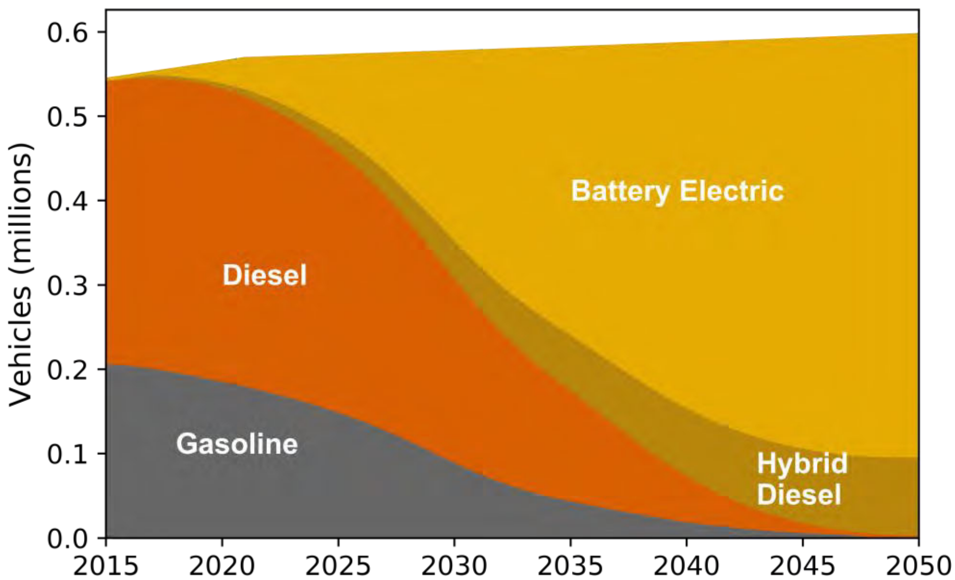
4.3.2 MEDIUM- AND HEAVY-DUTY TRUCKS

Like passenger vehicles, medium and heavy-duty trucks must undergo a transition from GHG intensive fossil fuels to a mix of low-carbon alternatives. There are a range of plausible technologies that can be used to decarbonize trucks, including: hybrid electric (diesel hybrid), battery electric (BEV), hydrogen fuel cell (HFCV), and biofuel derived diesel and compressed natural gas (CNG). In this analysis, we focus on electrification as the primary strategy to reduce emissions in medium-and heavy-duty trucks. Battery electric trucks have not yet been produced at scale but could represent an important transportation decarbonization technology. We assume that battery electric trucks are most immediately useful in the medium-duty trucking sector.

Major owners of medium duty fleets like UPS have begun to pilot battery electric parcel trucks (Winston 2018). Heavy duty truck electrification is more speculative. Barring substantial improvements in battery technology, the energy densities of renewable diesel and hydrogen may be attractive options for trucking services that involve heavy loads or long-distances.

In all scenarios over 80% of medium duty trucks and over 70% of heavy-duty trucks are electrified. This view of the future is premised on electric technologies being capable of serving all but the highest load and longest trips. The remaining trucks in the economy are powered by hybrid diesel drive-trains, fueled with 100% renewable diesel (Figure 18).

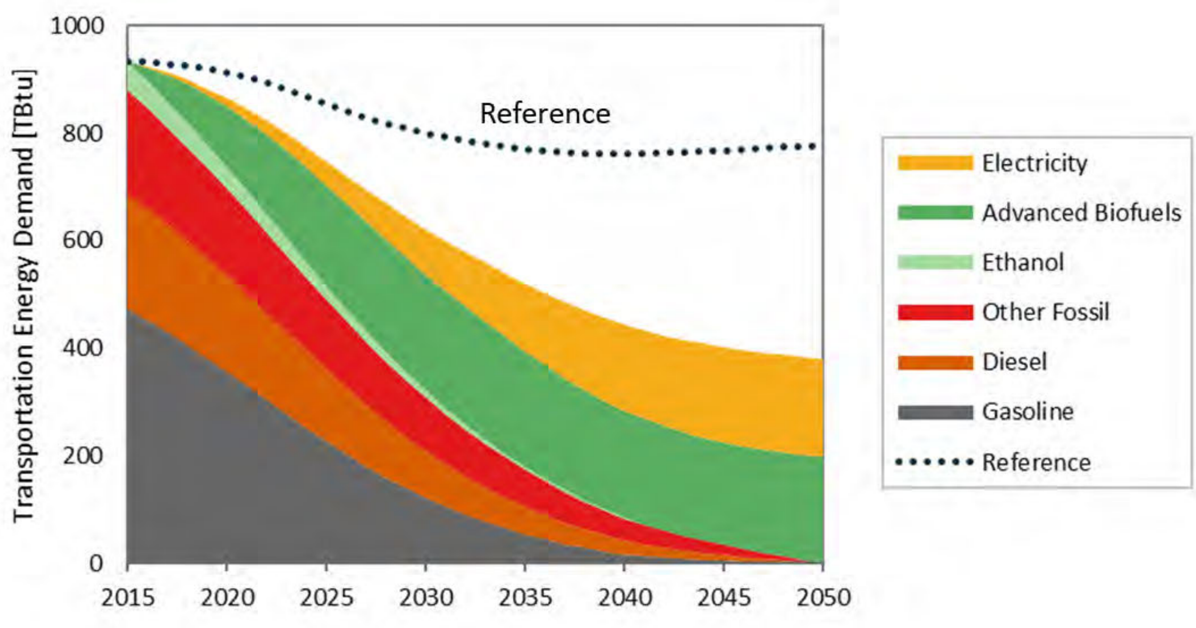
Figure 18. Millions of Freight Trucks by Type, All Scenarios, 2015 - 2050



4.3.3 ENERGY DEMAND IN THE TRANSPORTATION SECTOR

By 2050, in all scenarios, energy demands in the transportation sector are assumed be served entirely with electric or hybrid electric vehicles, with the remaining liquid energy demands provided by advanced, carbon-neutral biofuels. Total transportation energy demands in the mitigation scenarios are about half of the energy demands in the Reference scenario, due to the efficiency gains from electric drive trains in vehicles (Figure 19). Energy demands fall even in the Reference scenario due to the assumed efficiency gains of continued implementation of the federal corporate average fuel economy standards for vehicles.

Figure 19. Energy demand in the Transportation Sector, All Scenarios, 2015 - 2050



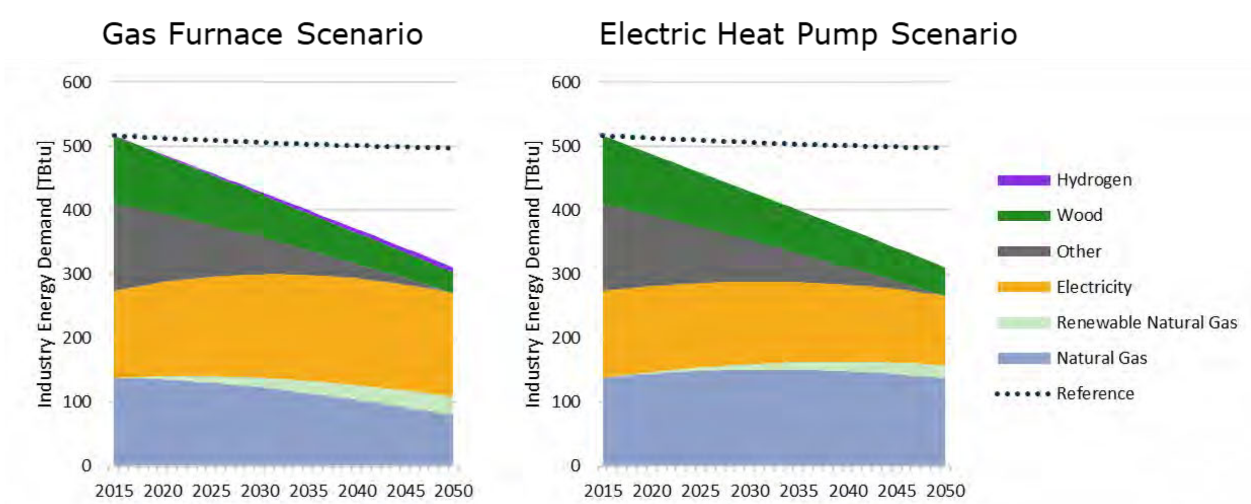
4.4 Industrial Sector

Greenhouse gas reductions from industrial energy emissions are achieved in these scenarios via three mechanisms: 1) energy efficiency, 2) decarbonization of fuels, and 3) electrification. Non-energy emissions reductions are also an important component of decarbonizing industry, particularly in sectors like cement, and are applied based on current research suggesting realistically achievable reductions.

Energy efficiency is assumed to reduce industrial demands for pipeline gas, diesel and electric power. Each scenario assumes a 30% reduction in total industrial energy demand via energy efficiency, relative to the Reference scenario. We assume that the petroleum refining industry in the region sees sharp decreases in output given the very low demand for refined petroleum products in all mitigation scenarios. Today, all refining in the Northwest occurs in Washington. We estimated the share of industry energy usage associated with refining using Washington State Emissions Inventory Reporting System data for 2014 (Washington Department of Ecology 2014). Based the emissions in that report, we assume that retired refinery capacity is equivalent to an additional 20% reduction in total industrial demand in Washington in 2050 relative to the Reference scenario.

The remaining energy demands in industry can be served in one of three ways: electrification, low-carbon fuels, and fossil-fuels. All scenarios use low-carbon fuels, primarily biomethane, to displace fossil natural gas in the pipeline. The renewable natural gas in the pipeline contributes to reducing emissions from the industrial sector. A distinction between the Electric Heat Pump and Direct Use Gas Scenarios is industry electrification. The Gas Scenarios rely on 30% electrification of industry natural gas to meet the 2050 emissions gap, reducing the direct use of natural gas in industry compared to the Electric Heat Pump scenarios (Figure 20). Industry electrification includes converting HVAC equipment to electric heat pumps, using electric resistance heaters in process heating and boiler applications, as well as using emerging electric technologies like ultraviolet pasteurization or induction melting.

Figure 20. Energy Demand in Industry by Scenario and Fuel Type, 2015 - 2050



The electrification of industrial energy usage in the Gas Scenarios is a transformational change in the sector. There may be emerging use cases where some industrial processes will experience productivity gains by converting to electric technologies, but cost per unit of heat will probably be the most salient feature for most of industry.

4.5 Buildings Sector

4.5.1 ENERGY EFFICIENCY

In all scenarios, carbon reductions are achieved in the buildings sector through high levels of energy efficiency. Conventional forms of energy efficiency that are applied in all scenarios include a complete transition to efficient LED lighting, as well as more efficient plug loads and equipment, ranging from refrigeration to dishwashers. High efficiency appliances achieve an Energy Star standard or beyond.

All scenarios assume substantial improvements in the building shells of buildings in the Northwest. In the PATHWAYS model, building shell improvements are modelled as a ‘stock’ measure. Building shell improvements are assumed to reduce space-heating energy services demand by 40% relative to today in individual retrofit of buildings. By 2050, almost 75% of buildings are assumed to have this more efficient building shell. We also assume that behavioral conservation measures, such as smart use of programmable thermostats, decrease energy services demand by 5% per building. The result is a 35% decrease in heat required to keep buildings warm across the entire Northwest building stock by 2050. These energy efficiency gains are an important tool to contain costs for the Gas Scenarios and the Electrification Scenarios.

4.5.2 SPACE HEATING

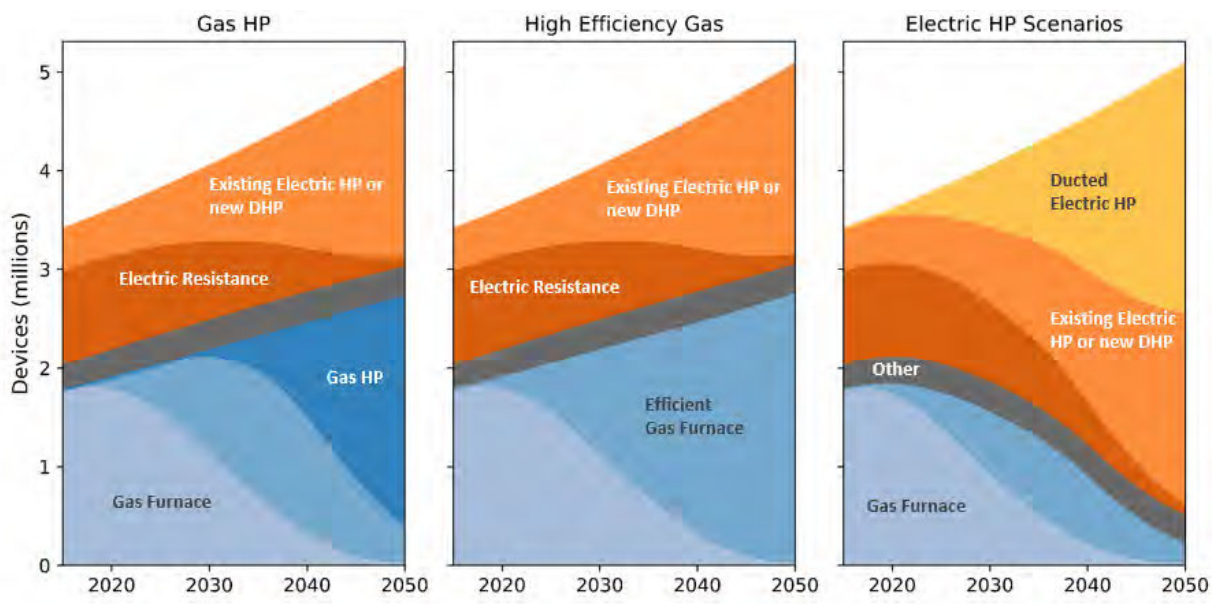
In nearly all scenarios, a transformation of space heating technology sales is envisioned as part of a low-carbon future. There are a wide variety of space-heating technologies in use in the Northwest today, ranging from natural gas furnaces to wood-fired stoves. All scenarios assume that electric resistance, diesel, and propane (LPG) heaters are replaced with ductless electric heat pumps, given that the lifecycle economics for such a replacement would be generally positive in all cases. Policy intervention may still be needed for this transition to overcome market barriers such as limited access to credit or split incentives for renters.

In the Direct Use Natural Gas Scenarios, continued use of the Northwest's existing natural gas distribution infrastructure is assumed to heat existing proportions of homes and businesses. The Electric Heat Pump Scenarios replace existing gas space- and water-heaters with electric air source heat pump technologies (Figure 21).

+ In the Gas Furnace Scenario, all new furnaces sold have an efficiency of 98% or greater by 2030, compared to an approximate 90% efficiency for a typical furnace installed in Northwest today (NEEA Residential Building Stock Assessment [RBSA]).
+ The Natural Gas Heat Pump scenario is an innovation case, where gas-powered heat pumps are brought to market on a wide scale by 2025. Natural gas heat pumps operate under similar principles as electric heat pumps and can achieve annual COPs of over 1.4 annually for space heating and 1.3 for water heating, without relying on electric resistance heating during extreme cold temperatures. E3 consulted with NEEA—a regional energy efficiency organization working to commercialize the technology—to better understand the characteristics of natural gas heat pumps (Interview). One notable feature of NEEA's preferred natural gas heat pump technology is that it may be well suited to provide both space- and water-heating from a single system.
+ The Electric Heat Pump Scenarios assume a near complete electrification of space-heating in the Northwest. The Electric Heat Pump Scenario assumes that, by 2030, 60% of the sales of space heating equipment in buildings are high efficiency air source heat pumps with an HSPF of 9.0. By 2040, 100% of sales of all space heating equipment in the region is assumed to be electric heat pumps. The Cold-Climate Heat Pump Scenario assumes that, by 2030, 60% of the sales of space heating equipment are higher performing, but more expensive, cold climate heat pumps, with an HSPF of 10.5. This share of new sales increases to 100% by 2040. Over time, homes that have, or

would have, installed gas heating equipment instead install an air-source heat pump. By 2050, almost every building in the region is heated by electric heat pumps or cold climate heat pumps. The scale and pace of this transition highlights the role of the consumer in achieving deep decarbonization. To achieve this transition, the purchase decisions of both homes and business must shift to electric alternatives. That trend would run counter to recent experience, where the share of gas heated buildings in the region is increasing (NEEA RBSA). The electric sector implications of space-heating electrification are discussed below, in section 4.7.

Figure 21. Millions of Residential Space Heaters, by Scenario, 2015 - 2050

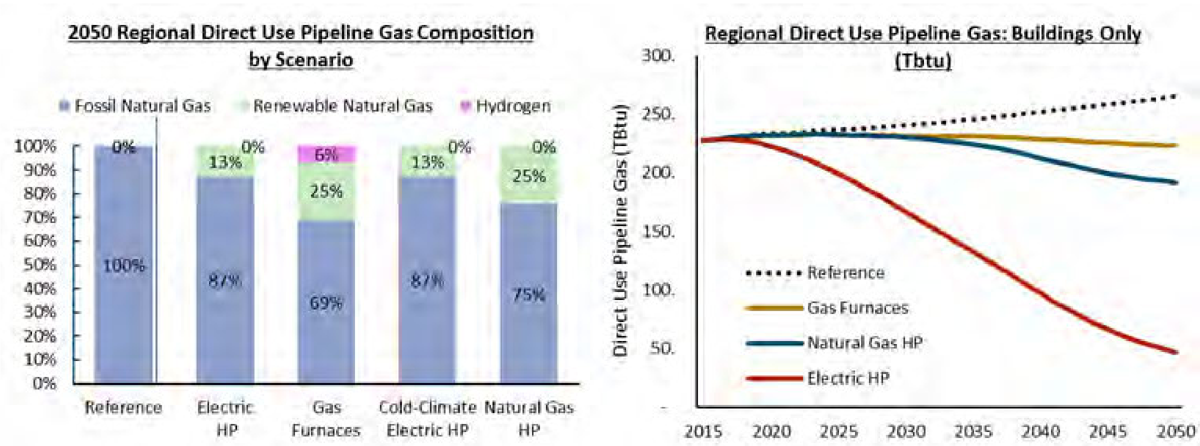


4.5.3 GAS USE IN BUILDINGS

A key element of greenhouse gas reductions in the Gas Scenarios is energy efficiency. Wide-spread adoption of efficient gas technologies—paired with the same aggressive shell measures used in the Electrification Scenarios—decreases gas throughput relative to Reference by between 18 and 26 percent compared to the Reference scenario.

The remaining pipeline gas throughput is partially decarbonized in the Gas Scenarios. The Gas Furnaces scenario uses a combination of biomethane and blended hydrogen to decarbonize 31% of direct use natural gas. The Natural Gas Heat Pump Scenario has a similar quantity of biomethane, but with its lower denominator has a higher blend of biomethane at 25% of direct use of natural gas. The Natural Gas Heat Pumps scenario avoids the use of relatively expensive hydrogen because of the additional energy efficiency this technology enables.

Figure 22. 2050 Composition of the Natural Gas Pipeline by Scenario, and Direct Use of Gas in the Buildings Sector Over Time, by Scenario



4.5.4 WATER HEATING

Both of the Electric Heat Pump Scenarios include wide-spread adoption of electric heat pump water heaters in Oregon and Washington. The heat pump water heater load shapes are derived from Ecotope, and are primarily driven by occupant use schedules, with some impact from outdoor air temperatures (Larson and Hannas 2014). While heat pump water heaters are larger than traditional tank water heaters and require more clearance around the unit, it is assumed that they can be installed in nearly all homes and businesses by 2050.

The Gas Furnaces scenario assumes wide-spread adoption of 85% efficient gas condensing storage tank water heaters. The Natural Gas Heat Pump scenario assumes that natural gas heat pump “combi” systems are installed to provide both space- and water-heating services to buildings. This is an important feature of the Natural Gas Heat Pump scenario, allowing customers to realize not only energy efficiency gains from adopting this technology, but also cost savings relative to the cost of purchasing a separate water heater and space heater.

4.5.5 PEAK HEATING LOADS IN THE NORTHWEST

Heating loads are the largest source of energy demand in a typical residential and commercial building in the Northwest. The importance of heating loads only increases as the temperature drops. E3 worked with Big Ladder Software to conduct building simulations in Energy Plus for three different building types using air source heat pumps. Results from that modelling show that electrification can cause large new loads in buildings. After accounting for weatherization and displaced electric resistance heat, electrification of space-heating adds incremental loads of between 17,000 and 37,000 megawatts to the region’s peak electricity demand. For context, the region’s entire hydroelectric system is about 33,000 MW, with an estimated peak capacity of 24,000 MW over a four-hour period.[15]

The Gas Scenarios examine cases where the proportion of homes[16]and businesses served directly by pipeline gas (inclusive of natural gas, renewable natural gas, and hydrogen) does not change over time. A

[15] Northwest Power and Conservation Council 7th Power Plan, Chapter 9: Existing Resources and Retirements: https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap09_existresources_2.pdf
[16] The share of gas heating is based on housing unit type, where there are 3 categories, including large-single family, small single-family attached, and multifamily.

combination of low-carbon gases and energy efficiency reduces the direct-combustion emissions per gas home by between 42% and 50% by 2050.

The Gas Furnaces Scenario assumes the installation of condensing gas furnaces and condensing gas storage tank water-heaters to reduce demand over time. Both technologies are commonly installed today. In order to achieve the economy-wide emissions target this scenario also includes a blend of both RNG and hydrogen in the pipeline to reduce the emissions intensity of pipeline gas. The Gas Heat Pump Scenario assumes the installation of natural gas-powered heat pumps, a technology which is not widely available today. Natural gas-powered heat pumps have an efficiency rating, or COP, of 1.3 to 1.4, creating a large enough reduction in demand that hydrogen blending into the gas pipeline is not necessary in this scenario to meet the 2050 economy-wide GHG reduction goal.

4.5.5.1 Building Stock in the Pacific Northwest

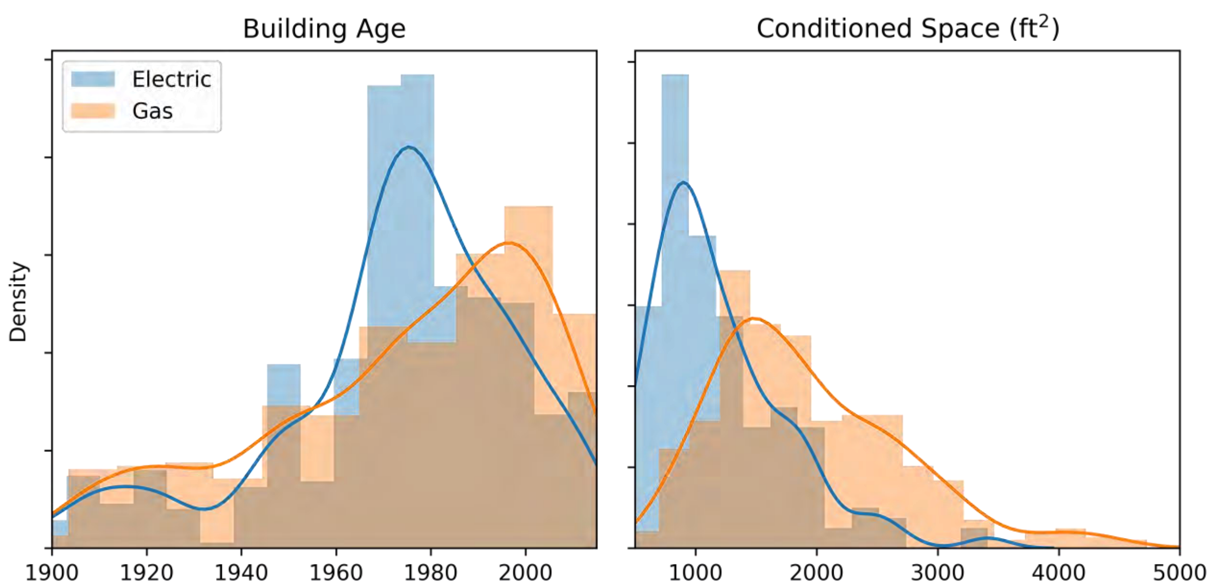
Most buildings in the Northwest are heated by either natural gas furnaces or electric resistance heaters. In Oregon, 58% of homes use natural gas as their primary source of space-heating, 33% of homes use electric heat and the remaining homes use a combination of oil, propane and wood. The current distribution of space-heating equipment in Washington is similar to Oregon (Table 5).

Table 5. Share of space heating and water heating by fuel type and state (%) (Source: NEEA RBSA)

Appliance	Fuel Type	Oregon	Washington
Space heating	Gas	58%	52%
	Electric	33%	42%
	Other	9%	6%
Water heating	Gas	50%	48%
	Electric	50%	51%
	Other	<1%	1%

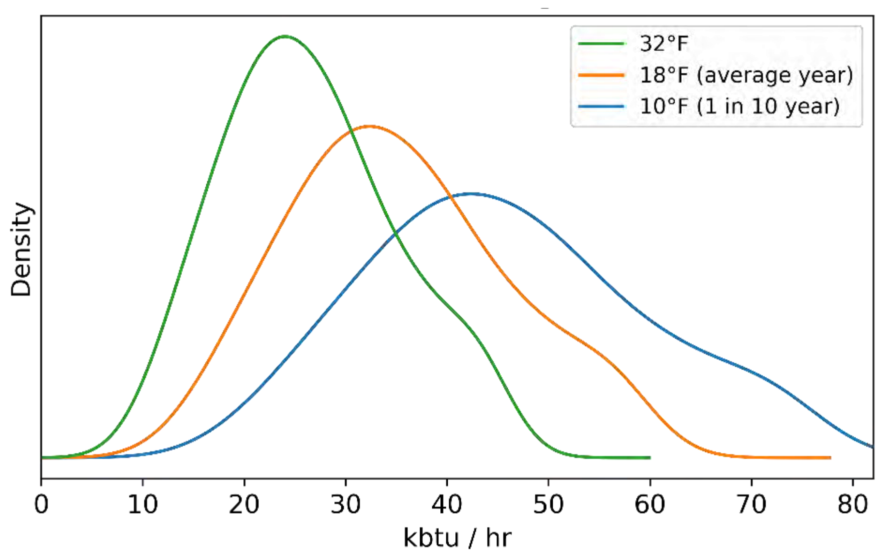
In the Northwest, approximately 35% of homes use electric heat. In general, these homes tend to be smaller and older than gas homes in the region (Figure 23). Whereas the average gas home in Oregon and Washington is almost 2,000 square feet and most likely was built in the 1990s or 2000's, an average electric resistance home in the region is 1,200 square feet and was most likely built in the 1970s. Gas equipment tends to serve larger loads, so its share of heating energy is higher than the stock shares in Table 2. For instance, natural gas serves 68% of regional space-heating needs despite being the primary source of heating for just over half of the residential housing units in Oregon and Washington.

Figure 23. Existing distribution of Pacific Northwest homes by vintage and heating fuel type, and by square footage and heating fuel type (Source: NEEA RBSA 2016)



Space heating and cooling loads are weather dependent. As the temperature drops, building heating requirements increase. Figure 24 shows the distribution of hourly space-heating demand for the gas-heated building stock within Northwest Natural's service territory at three different temperatures. At freezing, the median home requires 25 kbtu per hour (kbtu/hr) to maintain comfort. The average heating requirements increase to a peak of 37 kbtu/hr during an average winter (18° F) and 44 kbtu/hr during a particularly cold, "1 in 10 year", winter at 10° F. For reference, the largest residential heat pump widely available is 5 tons, rated to provide 60 kbtu/hr at 47° F and that output that decreases with temperature.

Figure 24. Distribution of heating requirements across NW Natural's housing stock at 7am, across three different temperatures (Source: NW Natural)



4.5.5.2 Performance of Electric Heat Pumps in the Pacific Northwest

Electrification of space-heating creates a large new weather dependent load for the Northwest electricity system to serve. This analysis considers the impact of a '1 in 10' cold-snap as a heuristic for the type of heating event that the electric sector will need to plan for in a high electrification regime.

This analysis considers two types of centrally-ducted electric heat pumps for residential and commercial buildings: a conventional air source heat pump system and an electric air source heat pump designed for better performance in cold-climates. The first heat pump system has an efficiency rating, or HSPF, of 9, equivalent to an annual COP of 3.2 (estimated regional average). These types of systems are commonly available in the Pacific Northwest region. For context, these systems are more efficient than the federal code minimum requirements of an HSPF of 7.7. The minimum requirements to receive an incentive from The Energy Trust of Oregon for an air source heat pump is an HSPF of 8.5 or greater, while the state of Oregon offers an incentive for ducted air source heat pumps with an HSPF of 9.5 or greater. The cold-climate system has an HSPF of 10.5, equivalent to an annual COP of 4 (estimated regional average). These systems are both more efficient overall and more expensive than the heat pumps with an HSPF of 9. Cold climate heat pumps are also currently less common and as a result are less well understood by some contractors and HVAC installers.

Both electric heat pump systems are efficient on an annual basis, requiring less on-site energy to heat buildings than gas furnaces or electric resistance heaters. The systems are most distinct in their performance during cold weather events. Consistent with the standard installation practices for heat pumps in cold climates, each system is assumed to be installed with electric-resistance back up heat. At the “lock-out” temperature, the heat pump operation is entirely replaced with less efficient electric resistance back-up heat to ensure that desired building temperature is maintained. The Electric Heat Pump scenario assumes that this temperature is 34 degrees Fahrenheit, while the Cold Climate Electric Heat Pump scenario sets that temperature at 5 degrees Fahrenheit. Table 6 lists the key parameters of the heat pump systems.

The Electric Heat Pump scenario represents a worldview where relatively efficient air source heat pump systems are adopted, but where installers and building occupants select and install the electric heat pumps systems to reduce the upfront capital costs, and do not have an incentive to optimize the performance of the systems for the broader electric grid during cold weather. The Cold Climate Electric

Heat Pump scenario is more consistent with a market-transformation future where cold climate heat pumps are specifically incentivized or required, or customers' economic interests are aligned with reducing system-wide winter peak demands.

Table 6. Comparison of electric heat pump performance assumptions by scenario

	Electric Heat Pump	Cold-Climate Heat Pump
Annual Efficiency (heating seasonal performance factor, HSPF)	9	10.5
Annual coefficient of performance, regional average estimate (Heat pump/ System)	3.0 / 2.5	4.0 / 3.8
Peak coefficient of performance (System)	1.0	2
Lock-out temperature (F)	34F	5F

Electric heat pumps both lose efficiency and produce less heat as the outdoor temperature drops. When there is a gap between building heating requirements and the maximum output of a heat pump, supplemental heat is required. The most common form of supplemental heat is an electric resistance element, though natural gas or propane furnaces can also provide supplemental heat (Center for Energy and Environment 2017, Wales & West Utilities 2018). For the purposes of this study, electric heat pumps are assumed to be supplemented by electric resistance heat.

After accounting for energy efficiency improvements and load diversity, we find that switching from gas to cold-climate electric heat pumps adds an incremental peak of 4.3 kW per home during a '1 in 10' heating event. Similar incremental peak loads occur in the commercial sector, where conversion to air source heat pumps increases electric load by 2 W/ft^2. These loads are offset, somewhat, by replacing electric resistance heaters with electric heat pumps. The Appendix provides additional detail on how building electrification loads were built up in this analysis. Table 7, below, outlines some key conditions under which actual building electrification peak load impacts could either be higher our lower than our findings.

Table 7: How peak load estimates could change

Winter peak could be higher with:	Winter peak could be lower with:
+ Less progress on building shell retrofits and improvements in new buildings + Winter temperatures colder than the 1-in-10 heuristic used in this analysis + Less diversity in building heating loads during cold temperatures + More reliance on supplemental heat during cold weather (e.g. HVAC installation practices that are not focused on meeting peak heat needs, or poor equipment maintenance) + Higher coincidence of space heating, water heating and electric vehicle charging	+ Market transformation that reduces the cost of non-weather dependent ground source heat pumps + Technology improvements that improve the performance of cold-climate heat pumps + More diversity in building heating loads at cold temperatures + Demand response & flexible loads in industry, electric transportation and other non-weather dependent end-uses + Heat storage in buildings, including pre-heating buildings + Duel-fuel heating systems: electric heat pumps paired with a furnace or boiler powered by gas or propane that provides supplemental heat + Increased winter minimum temperatures due to climate change + New electric transmission could also help to address winter peaks

4.6 Electric Sector Capacity Expansion and Operations

The electric sector is the lynchpin of deep decarbonization. In each scenario, clean electric generation displaces fossil fuels, both directly in the electric sector and through electrification of end uses elsewhere in the economy. As discussed in the methods section of the report, the electricity sector is modeled using the RESOLVE model to evaluate the costs and generation mix associated with meeting a given set of electricity demands and an electricity sector carbon constraint, as defined in each scenario.

For this analysis, we simulate the electricity sector under a carbon budget. The carbon budget defines a maximum amount of carbon which the electricity sector can emit. The greenhouse gas accounting convention reflects a consumption-based approach, in which the emissions attributed to the region includes in-region generation, external resources owned by utilities which serve load within the region, and "unspecified" imports to the region, based on a deemed emissions rate of 0.43 tons/MWh. This accounting convention is based on rules established by the California Air Resources Board – for further details see the E3 "Pacific Northwest Low Carbon Scenario Analysis" Study.[17] The carbon budget is an upper bound on emissions, not an emissions target; if it is economic to procure more zero-carbon energy, meeting a lower emissions target than the required budget, RESOLVE will do so.

This study models a suite of scenarios to investigate strategies to deep decarbonization. A Reference Scenario reflecting current policies and trends serves as a point of comparison for the decarbonization scenarios. This Reference Scenario models existing statutory Renewable Portfolio Standard (RPS) goals, including Oregon's 50% RPS requirement for large IOUs and Washington's 15% RPS by 2020. This results in a region-wide, weighted RPS goal of 20% by 2040, which is held constant through 2050. Under the various decarbonization scenarios, the carbon budget for the electricity sector is set such that the total

[17] E3, "Pacific Northwest Low Carbon Scenario Analysis: Achieving Least-Cost Carbon Emissions Reductions in the Electricity Sector," December 2017. Available at: http://www.publicgeneratingpool.com/wp-content/uploads/2017/12/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf

scenario will achieve the 80% by 2050 carbon target. Table 8 below reflects the RPS assumption and carbon budget requirement by scenario.

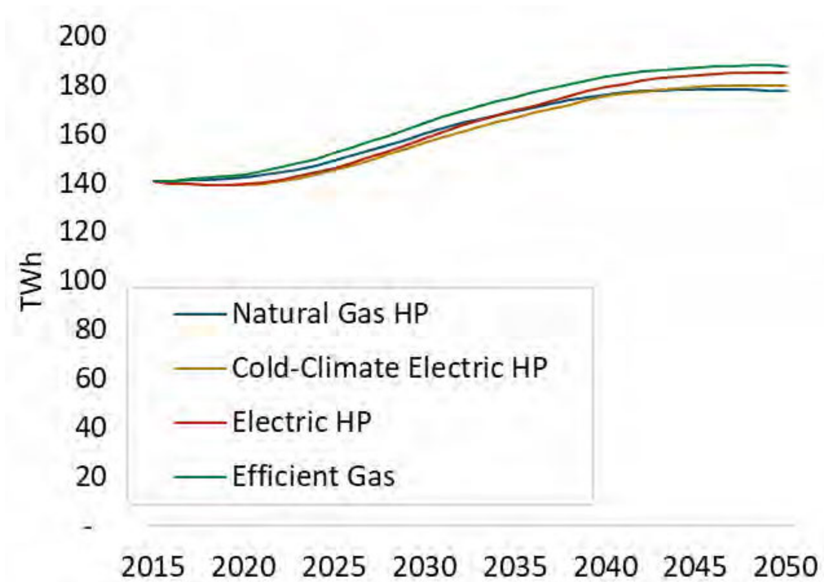
Table 8. Electricity sector RPS and carbon budget assumptions by scenario

	Regional RPS	Carbon Budget / Constraint (2050)
Reference	20% by 2040	None (unlimited)
Direct Use Gas Scenarios	20% by 2040	3 MMT (97% zero-carbon)
Electric Heat Pump Scenarios	20% by 2040	5 MMT (95% zero-carbon)

4.6.1 ELECTRICITY DEMAND

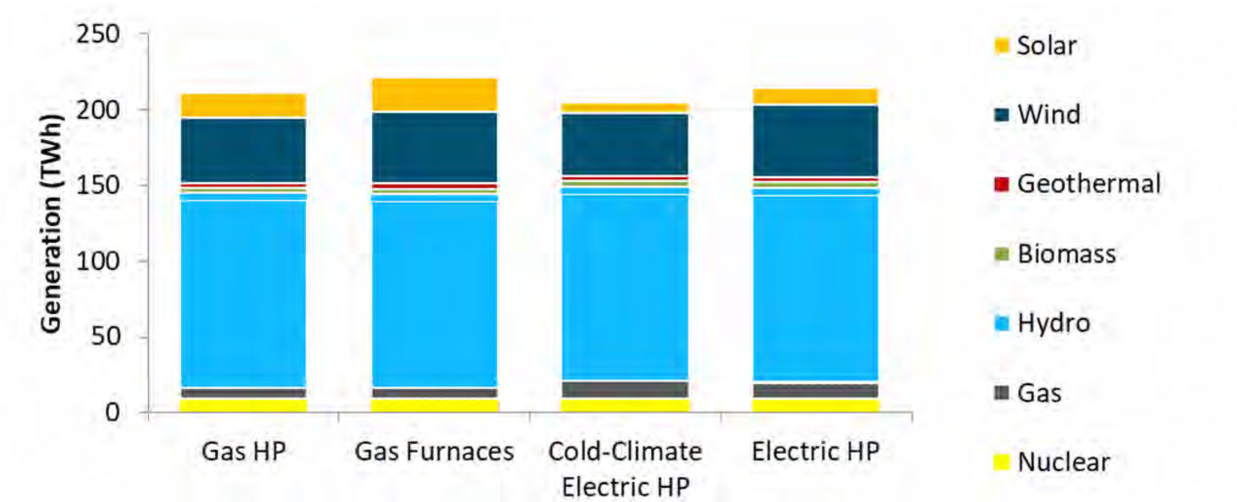
Electric demand increases through 2050 in all decarbonization scenarios. Population growth and decarbonization driven electrification are the primary drivers of load growth in each scenario. Load in PATHWAYS Reference case is expected to grow at 0.2% per year after energy efficiency, while the mitigation scenarios see load growth of 0.67% to 0.84% per year. The Direct Use Gas Scenarios see higher load growth than the Electric Heat Pump Scenarios due to industrial electrification (both Direct Use Gas Scenarios) and due to electricity loads associated with the production of hydrogen via electrolysis in the Gas Furnace scenario. By 2050, the Gas Furnace Scenario has the largest electricity loads due to energy intensive hydrogen electrolysis (Figure 25).

Figure 25. Annual Electricity Demand by Scenario, 2015 - 2050



While the hourly loads look quite different between the scenarios, each of the scenarios has a similar magnitude of annual electric loads in 2050, served by an electric generation mix that is 95% to 97% zero carbon. The largest source of energy in the region continues to be hydropower. Renewables displace most existing fossil generation in the region—including all coal—leaving 3% to 5% of generation from natural gas to balance the system (Figure 26). There is only a modest amount of renewable curtailment in this analysis, falling around 5% of generation in each case.

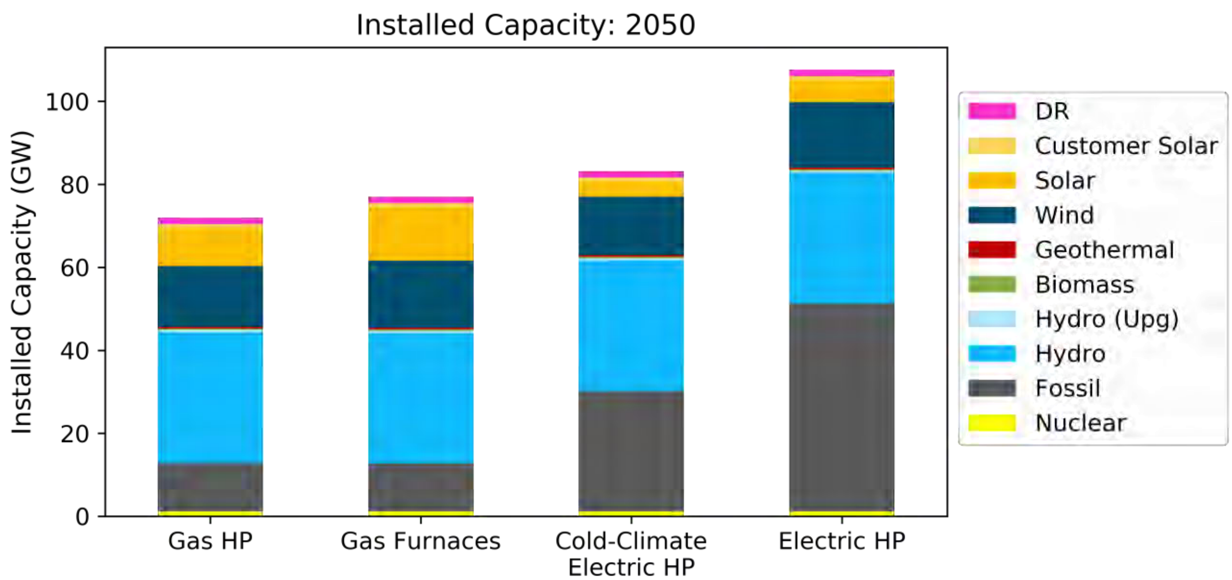
Figure 26. Electricity Generation Mix by Scenario, 2050



4.6.2 ELECTRICITY GENERATION CAPACITY

The Northwest electricity system must expand in every scenario to meet higher electricity demands. There are three main reasons for that expansion: natural growth in loads due to population and economic growth (which is offset by energy efficiency in the mitigation scenarios), greenhouse gas constraints which require new zero-carbon resources to be built, and electrification measures that increase electricity demands, particularly winter peak demands. The 2050 installed resource capacity assumptions by scenario are shown in Figure 27 below. For context, across the Pacific Northwest, the total installed capacity for renewables in 2016 was approximately 10,000 MW, mostly wind. In this analysis, the installed capacity of renewable resources approximately doubles by 2050, to 19,000 MW in the Cold Climate Heat Pump Scenario and to 30,000 MW in the Natural Gas Furnace Scenario, including a mix of solar and wind. The 11,000 GW of additional renewable capacity in the Natural Gas Furnace Scenario compared to the Cold Climate Heat Pump Scenario is used to provide low-carbon power to produce hydrogen from electrolysis, which is blended into the natural gas pipeline. Higher levels of renewable capacity are also built in the Natural Gas Heat Pump scenario to power industrial electrification.

Figure 27. Installed electric generation capacity, 2050



4.6.3 ELECTRIC HEAT PUMP LOAD SHAPES AND CONTRIBUTION TO WINTER PEAK

The largest cause of capacity expansion in the Electric Heat Pump scenarios are the peak loads associated with the electrification of building heat. A critical feature of these loads is that they are inherently weather-dependent and weather varies both within and between years.

Current electricity sector peak planning practices consider a variety of weather conditions, generator outages and other contingencies to establish a planning reserve margin (PRM). A PRM is expressed as an incremental percentage of capacity that is needed on top of expected loads in an average year to ensure electric reliability through a range of contingencies ranging from generator outages to variations in weather dependent loads. Today, a PRM of 15% is typical in many jurisdictions across the Western United States, including in the Pacific Northwest (NERC 2017). Adding weather dependent space-heating loads to a winter-peaking electricity system will, all else equal, increase the variance of plausible load conditions beyond those seen in studies that are the basis for current planning standards.

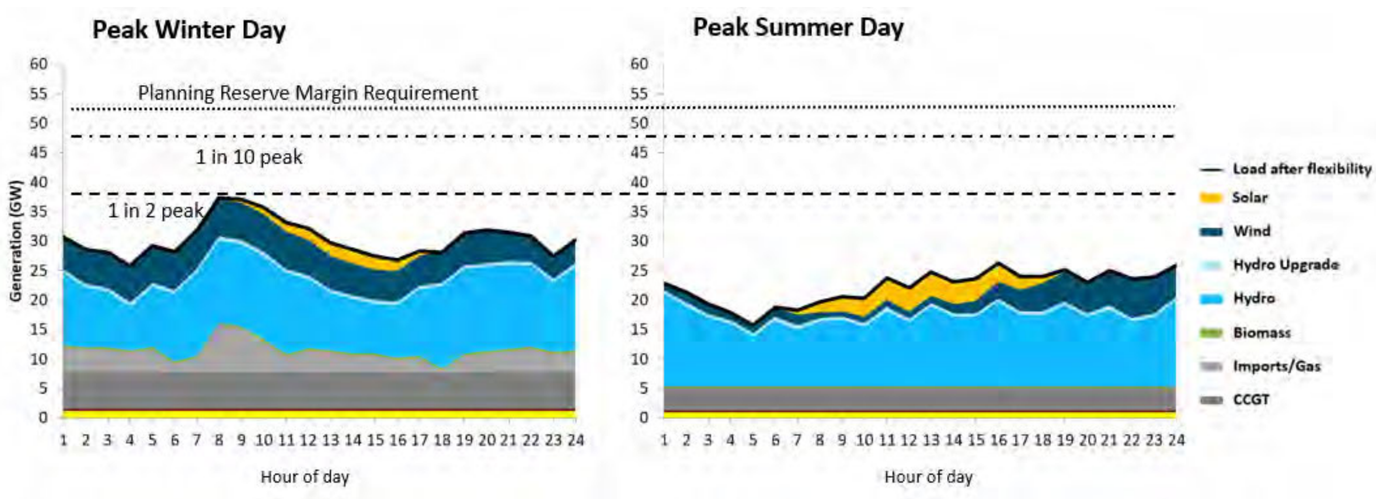
E3 used a ‘1 in 10’ year cold weather event to help evaluate the type of peak event that electricity sector planners would need to account for in a high building electrification future. The difference in peak heating loads between a 1-in-10 weather year and an average ‘1 in 2’ weather year exceeds 9 GW for the Cold-Climate Heat Pump Scenario in 2050, highlighting the sensitivity of load from heat pumps at cold temperatures. Put differently, the system-wide coincident peak loads for the Cold-Climate Heat Pump Scenario are 25% higher in a ‘1-in-10’ winter than in a ‘1-in-2’ winter. Based on this information, we derive an estimated requirement of a 35% planning reserve margin (PRM) in the Cold-Climate Heat Pump Scenario. This PRM is then applied to the ‘1-in-2’ peak loads.

The estimated 35% PRM figure incorporates the 25% inter-annual variation in load under cold temperatures, with the remaining 10% of the PRM accounting for contingencies ranging from generator outages to forecast uncertainty. The estimated 35% PRM was applied to the ‘1-in-2’ peak loads in the RESOLVE model. We compared this approach to an alternative method of applying a 10% PRM to the ‘1-in-10’ peak loads in RESOLVE and the RESOLVE model peak capacity requirements between these two approaches were within 200 MW.

It is important to note that both methods are a heuristic for how a PRM would be calculated and applied in a more detailed electricity resource planning process. To develop a more detailed analysis of the peak capacity needs under a high building electrification, high renewables future, a loss-of-load probability analyses would be needed that accounted for many more contingencies and weather conditions than are included in this study. However, for the purposes of this kind of long-range, scenario planning exercise, we believe that this heuristic-based approach provides an appropriate estimate of the peak capacity requirements.

Figure 28 below illustrates the hourly load shape and generation supply during a peak demand day in the winter and in the summer, under 1-in-2 winter weather conditions, 1-in-10 winter weather conditions and the planning reserve margin that is applied in this analysis.

Figure 28: Hourly loads, peak winter day and peak summer day in 2050, Cold-Climate Heat Pump Scenario

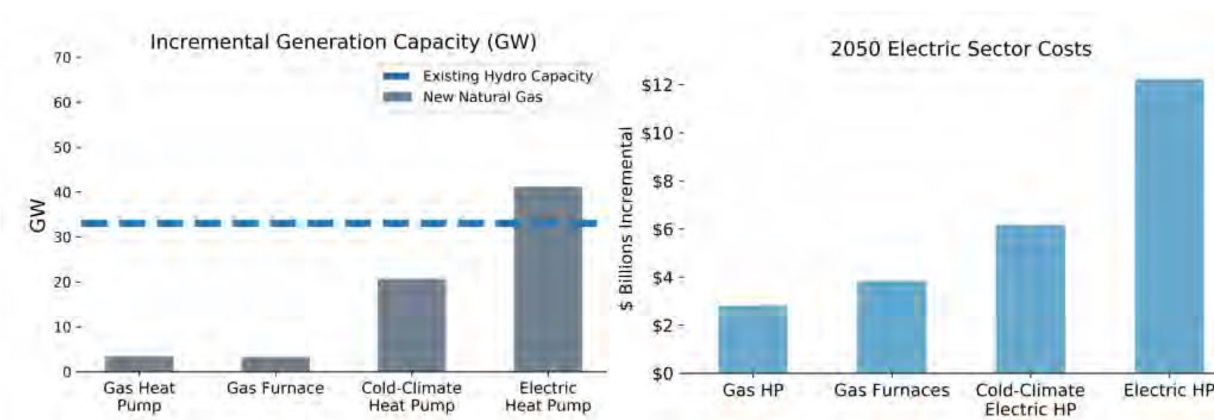


Variable renewables can provide a portion of peak capacity requirements, but that contribution is de-rated by these resources' effective load carrying capacity (ELCC). ELCC metrics capture the outage rate of a given resource. For thermal plants that is equivalent to a period of maintenance or refueling, but for variable resources the ELCC also captures periods of low wind or solar output. There are 18,000 MW of variable renewable energy installed in the Cold-Climate Heat Pump scenario, but after the ELCC adjustment these resources only contribute 3,500 MW towards the region's peak planning requirement.

The remaining incremental peak load—between 17,000 MW and 37,000 MW in the Electrification Scenarios—are served by firm resources, meaning natural gas combustion turbines, hydro-electric power and battery energy storage. In all scenarios, the RESOLVE model selects natural gas combustion turbines to provide the bulk of the firm capacity not met by variable renewable energy (Figure 29). The incremental cost to the region's electric grid of serving peak heating loads—that is the difference in electric peak in an average year versus a 1-in-10 heating year—exceed $1.9 billion annually.

An alternative source of capacity to serve peak loads could be battery or pumped-hydro energy storage. These technologies can provide firm capacity insofar as they are able to reliably charge and discharge during peak demand events. A determinant of these technologies' ability to provide reliable power during peak demand events is the storage duration of batteries and pumped-hydro resources.

Figure 29. 2050 incremental firm capacity build by scenario and 2050 electricity sector cost by scenario



We tested a "no new gas" sensitivity, in which only new energy storage could be selected to meet capacity needs in the RESOLVE model, and new gas capacity is not allowed to be built. This sensitivity assumes that a 10-hour energy storage duration could achieve the full capacity value needed to meet the winter peak, and that renewable resources would be available to charge the energy storage during the peak demand times in the winter. The incremental cost of using 10-hour energy storage, rather than combustion turbines to meet the peak demand, adds an additional $2 billion per year to the electricity sector costs in 2050, in the Cold Climate Heat Pump Scenario.[18]

However, this study did not include a detailed loss-of-load probability analysis to evaluate the expected load carrying capacity of battery storage under these conditions. As a result, this "no new gas", energy storage sensitivity may underestimate the cost of reliability serving winter loads if significantly more low-carbon resources (wind and solar) are needed to fully-charge the energy storage facilities during the winter. capacity contribution of energy storage under these future high-load, high renewable energy systems are very uncertain, especially in a winter-peaking system when extended periods of low hydro (drought), wind, and solar output are taken into account. While chemical battery technologies have been improving, it may not be possible for batteries and pumped storage to provide sufficient energy to serve loads during extended periods of low renewable output and high peak loads, especially during an extended cold snap, in which multiple days of peak or near-peak system loads can be expected to occur. A detailed analysis of the capacity value of energy storage under these future conditions is beyond the scope of this analysis.

The electric sector results from the RESOLVE model represent a limited subset of supply and demand conditions associated with deep decarbonization. These results inform the magnitude of low-carbon generation needed in the region to achieve deep decarbonization and the impacts of peak heating events on the region's electricity system. These results are not a substitute for a more detailed reliability analysis to assess the ability of the region to serve loads under a variety of supply and demand conditions. A loss-of-load-probability analysis is needed to more fully explore the range of possible load conditions under high electrification and how these conditions coincide with available energy supply.

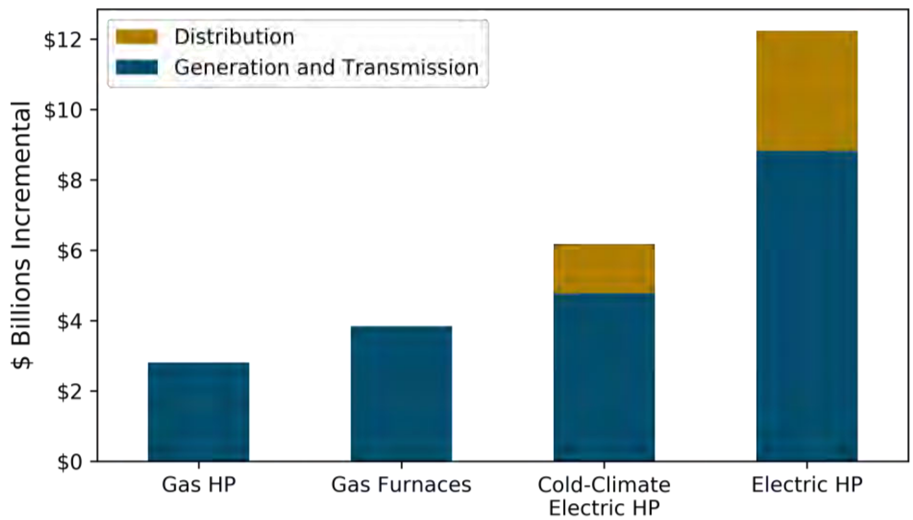
[18] The incremental cost would be higher in the Electric Heat Pump Scenario.

4.6.3.1 Incremental distribution costs

RESOLVE does not model electricity distribution system costs. Higher peak loads will require reinforcements of distribution infrastructure from the substation to the service drop. In fact, it is possible that the peak impacts of electrification could be more acute in the distribution system given that there will be less load diversity on any individual circuit or substation than for the region as a whole.

This analysis uses a single long-run marginal cost of service. That figure is in terms of \$/kW-year, which is the annualized cost of individual distribution investments (i.e. similar to amortization of a home mortgage). A more granular figure would require a feeder by feeder analysis that assesses how much spare capacity is available in the region's distribution system, and what the grid upgrade costs would be under high electrification. No such analysis has been done in the region, but studies along those lines have been done in the United Kingdom (Delta Energy & Environment 2016). Those studies find that the grid upgrade costs under a high building electrification scenario exceed \$100/kW-year when planning for a '1 in 20' heating event. We used that figure as a reference point to pick the highest distribution marginal cost listed in the Northwest Power and Conservation Council's 7th Plan. That cost is \$76/kW-year (2012\$) and is applied to all incremental peak load as an adder to the generation and transmission costs in RESOLVE (Figure 30). There are no incremental distribution costs in the Gas Scenarios, reflecting the aggressive energy efficiency measures in all mitigation cases. The incremental costs in the Electric Heat Pump Scenarios are largely driven by peak space-heating loads.

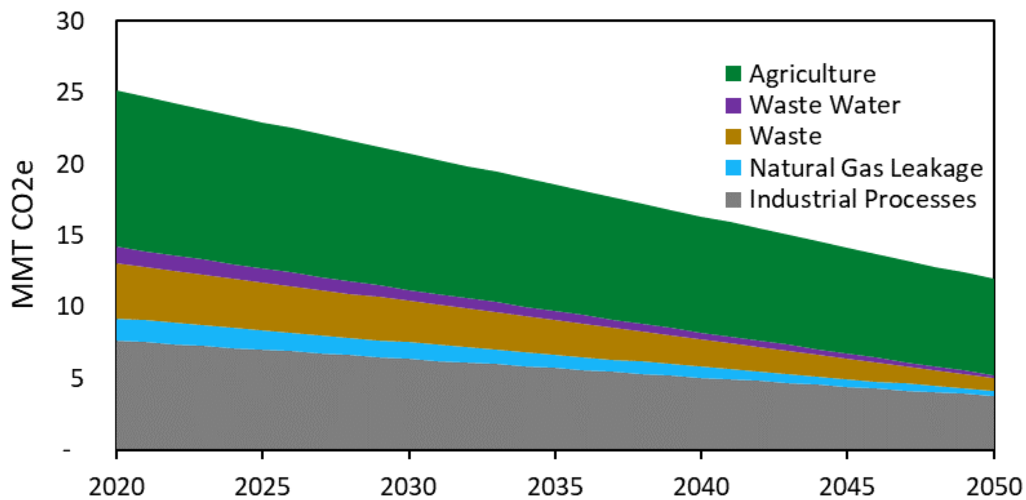
Figure 30: RESOLVE Costs, Including a Distribution Adder



4.1 Non-Combustion GHG Emissions

Each scenario assumes a 53% reduction in non-combustion emissions relative to 1990 (Figure 31). Non-combustion greenhouse gas emissions are gasses that contribute to global warming but are not directly the result of combusting fossil fuels. Examples include methane from biogenic and anthropogenic sources and other high global warming potential gases such as fluorinated gases used in refrigeration, air conditioners and heat pumps. The measures identified are consistent with the California Air Resources Board Short Lived Climate Pollutant Strategy (CARB 2017). Achieving these reductions will require action across multiple sectors of the economy, ranging from industry to agriculture. In some cases, these mitigation measures are complementary to energy system mitigation measures. A prime example is manure management, where we assume an 80% reduction in methane emissions and 452,000 dry tonnes of this feedstock is converted to advanced biofuels. Other non-combustion emissions reductions are potentially more challenging. For instance, we assume that emissions from enteric fermentation can be reduced by 80% and cement emissions reduced by 10%.

Figure 31: Non-combustion emissions



4.2 Scenario Costs

The total economy-wide costs for each scenario are calculated as the sum of the PATHWAYS model costs (all sectors except for electricity) and the RESOLVE model costs (electricity). Total costs are calculated on an annual basis including amortized capital costs for energy infrastructure in each sector, associated operations and maintenance costs, and fuel costs. The cost of each mitigation scenario is reported as an annual increment over the Reference case. These costs are meant to capture the direct incremental costs of the energy transition in terms of capital costs and fuel savings. The scenario costs do not include or reflect macroeconomic effects (e.g. jobs or structural changes to the economy), nor do they include avoided externality costs like the social cost of carbon or changes in health outcomes or costs due to changes in regional air quality.

4.2.1 COST UNCERTAINTIES

The economy-wide scenario costs calculated in this analysis are sensitive to input assumptions, particularly for measures that differ between scenarios. Key sources of cost differences between scenarios in this analysis include: the heating equipment deployed in buildings, the levels of industry electrification, and quantities of biofuels used. The costs of these measures are uncertain, particularly when projected out to 2050. The cost sensitivities and ranges presented below seek to capture some of that uncertainty.

4.2.1.1 Building equipment cost ranges

This analysis compares four different types of heating equipment in buildings. E3 evaluated a variety of sources to identify multiple cost estimates for each technology modelled. Ideally there would be a single data source that has a credible, comparable set of cost figures for each technology. To the best of our knowledge, no such data source currently exists. Table 9 lists the costs of space-heating equipment evaluated in this study. These costs define the low- and upper bounds of the capital cost sensitivities in Figure 32. All the heat pump technologies have a wide range of capital costs. Costs can vary for a variety of reasons, with the largest source of uncertainty being the non-equipment install costs associated with installing heat pump technologies. For example, if duct work is required to increase air flow throughout the home, or new electrical panel upgrades are required, the costs for a heat pump retrofit can be significantly higher than the capital cost of the equipment alone.

Table 9. Ranges of installed capital costs assumed for space heating plus water heating equipment, by type and data source

	Natural Gas Furnace	Natural Gas Heat Pump	Electric Heat Pump	Cold-Climate Electric Heat Pump	Ductless Air-Source Heat Pump
U.S. Department of Energy (National Energy Modelling System)	$3,000	$14,700	$5,100		
Energy Trust of Oregon			$10,200	$15,100	
Northwest Energy Efficiency Alliance		$7,000			$3,900
National Renewable Energy Laboratory	$2,500		$4,500	$6,000	$1,800

4.2.1.2 Biofuel cost uncertainty ranges

All scenarios in this analysis rely on biofuels to reduce the emissions intensity of remaining liquid and gaseous fuel demands. The PATHWAYS Biofuels Module simulates a regional market for biofuels, identifying a single clearing price for avoided CO2 emissions across all biofuels. That clearing price is sensitive to the cost of raw feedstocks, as well as the efficiency and costs of the conversion process from feedstocks to final biofuels. We estimate a high- and a low-end cost for biofuels by changing the final delivered fuel price for each final biofuel by plus or minus 20%.

4.2.1.3 Electrolysis and industrial electrification capital cost uncertainty ranges

There are also uncertainties in the capital costs of two key technologies—electrolysis and industrial electrification. Hydrogen electrolysis is a well understood process but has only been deployed at a limited scale. The capital costs of electrolysis today are assumed to be $1,127/kW, but these fall over time as demands for hydrogen fuels increase and learning-by-doing effects occur. The annual, or levelized, cost of hydrogen infrastructure also depends on its utilization. Hydrogen produced at a high capacity factor will cost less on a dollars per unit of energy produced basis than hydrogen produced at a low capacity factor, given the same electricity costs. The costs of converting from fossil fuel-powered to electric processes in industry are also uncertain, in part because the industrial sector is heterogeneous.

In this analysis both electrolysis and industry electrification capital costs are represented as a levelized ($/GJ) cost (Table 10). Costs in Table 10 do not capture cost of electricity associated with these mitigation measures. All electricity sector costs associated with industry electrification and hydrogen electrolysis are captured in RESOLVE. In 2050, RESOLVE costs in the Gas Furnaces scenario are $1 billion higher than in the Natural Gas Heat Pumps scenario.

Table 10: Hydrogen and industry electrification cost uncertainties

	Low - $/GJ	Mid - $/GJ	High - $/GJ
Hydrogen electrolysis capital cost uncertainty ranges	-20%	$35.3 (2018) $19.3 (2050)	+20%
Industrial electrification capital cost uncertainty ranges	$5	$5	$10

4.2.2 SCENARIO COST RESULTS AND DISCUSSION

PATHWAYS scenarios evaluate complex and uncertain futures. Results do not prescribe an optimal mitigation pathway, but instead test "what if" questions that can help inform future rounds of analysis and policy-making. Indeed, scenario results are sensitive to assumptions, many of which are fundamentally uncertain over the three-plus decades considered in this analysis.

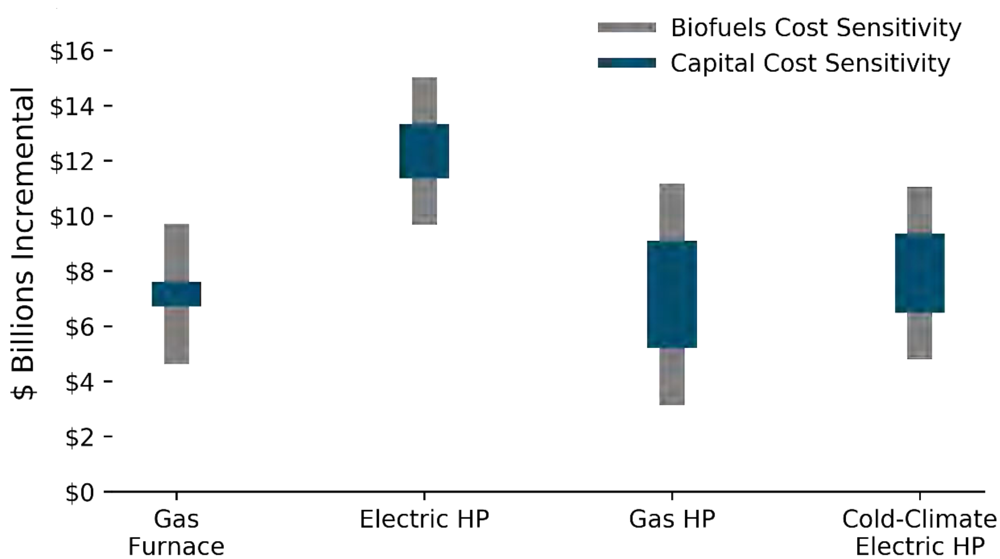
Figure 32 shows the range of scenario costs in 2050 relative to the Reference case. The cost ranges reflect two sensitivities. The cost ranges shown in the blue bars reflect uncertainty about the capital costs of building space-heating, industry electrification and hydrogen production costs. The narrow, grey portion layers the biofuels price uncertainty on top of the capital cost uncertainty, reflecting a biofuels cost range of +/- 20% compared to the results from the PATHWAYS biofuels module.

The 2050 costs of the Direct Use Gas Scenarios and Cold-Climate Electric Heat Pump scenario are similar in 2050, representing an incremental cost in the range of $4 to $10 billion per year in 2050. This range falls within 1% of the projected combined Gross State Product of Oregon and Washington. The Electric Heat Pump scenario shows the highest scenario costs due to the cost of serving the unmitigated, large winter peak load.

The average scenario costs range from $40/ton to $190/ton CO_2e in 2050 (in real 2017 dollars), relative to the Reference scenario depending on the future capital costs and fuel prices assumed. The average cost per ton metric means that some measures are far less expensive than this, while other measures are more expensive. This range reflects the wide range of uncertainties in projecting future scenario costs. Overall, these average GHG abatements costs ($40/ton to $190/ton CO_2e) are generally lower than the most recent estimates of the global social cost of carbon, which has a median cost of $417/ton CO_2, (and ranges from $177 to $805/ton CO_2). [19] The global social cost of carbon represents the expected economic damages to be incurred by climate change, per ton of CO_2 emitted.

[19] Ricke, K., L. Drouet, K. Caldeira, M. Tavoni, "Country-level social cost of carbon," *Nature Climate Change*, Vol. 8, October 2018 895-900. Available at: **https://www.nature.com/articles/s41558-018-0282-y.pdf**

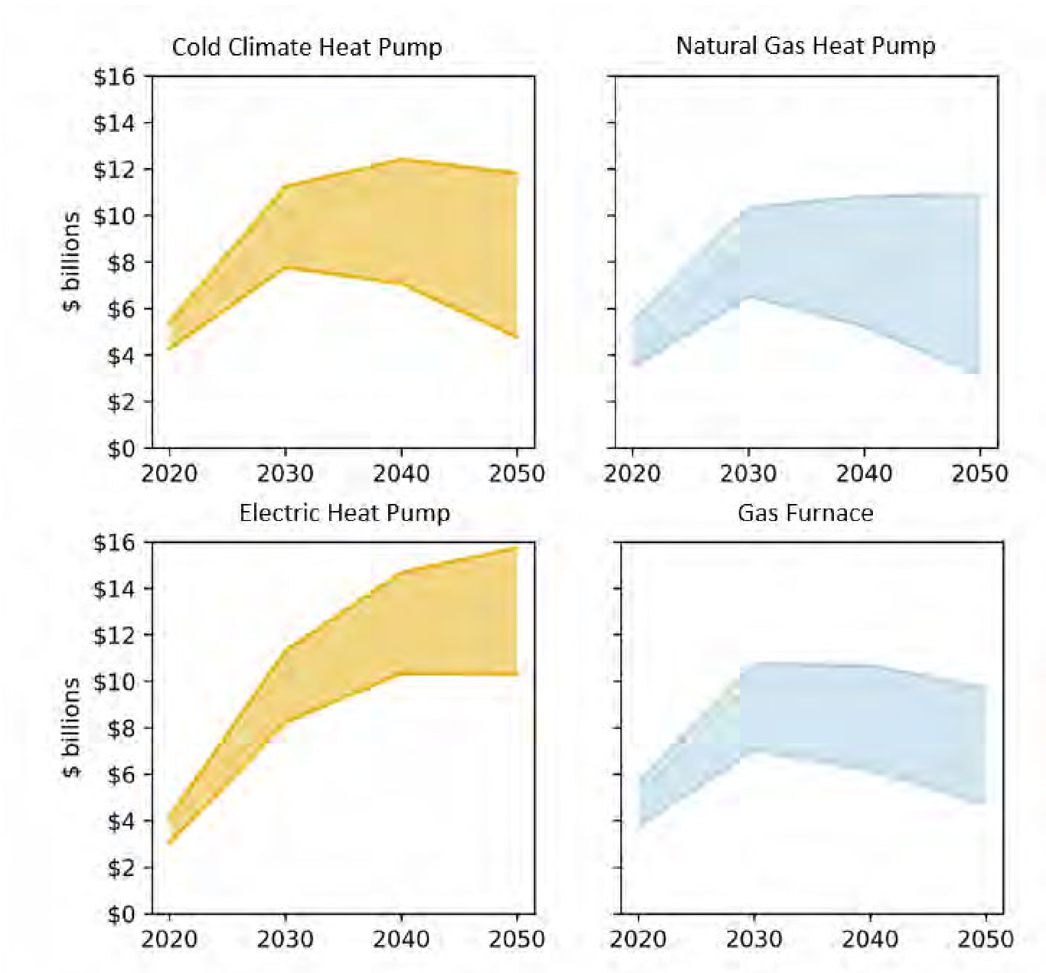
Figure 32. 2050 Mitigation scenario costs relative to Reference scenario, including capital and fuel cost sensitivities



Summary of Range of 2050 Mitigation Costs Relative to Reference Scenario:
Gas Furnace Scenario: $5 - $10 billion
Gas Heat Pump Scenario: $3 - $11 billion
Cold Climate Heat Pump Scenario: $5 - $11 billion
Electric Heat Pump Scenario: $10 - $16 billion

Each scenario carries incremental costs throughout the study period (Figure 33). These costs increase most rapidly between 2020 and 2030 as markets for biofuels scale and relatively more expensive technologies are deployed. Over time, the combined impact of technology cost decreases and continued energy efficiency progress stabilize scenario costs. In fact, in the lower end of the cost sensitivity ranges the cost of mitigation begins to drop post-2030. This result underscores the critical role of ongoing technology innovation and energy efficiency in achieving deep decarbonization.

Figure 33. Mitigation scenario costs relative to Reference scenario, including capital and fuel cost sensitivities, 2020 - 2050



5 Conclusions

The emissions reduction scenarios modelled in this analysis represent a transformation of the energy economies of Oregon and Washington. Rapid gains in energy efficiency, electrification and the development of low-carbon fuels are necessary for any strategy that reduces emissions by 80% below 1990 levels. This analysis takes an economy-wide view on regional decarbonization, with a focus on the role of buildings.

The results suggest multiple plausible technology pathways for the buildings sector in achieving economy-wide deep decarbonization, though each comes with risks and challenges. Indeed, no single strategy for buildings appears to be definitively the most cost-effective, when considered in the context of an economy-wide decarbonization strategy. Given this uncertainty, it would be prudent from a policy perspective to encourage the commercialization of renewable natural gas and hydrogen along with high efficiency space heating technologies in buildings. A number of "no regrets" decarbonization strategies are also identified including: 1) continued support for energy efficiency in buildings, 2) rapid electrification of the transportation sector, and 3) deployment of zero-carbon electricity generation.

In all scenarios, a combination of fossil and renewable natural gas, either used in homes or in new power plants, continues to serve winter peak heating, and is consistent with achieving an 80 percent reduction in greenhouse gases in the region.

5.1.1 MAINTAINING GAS HEAT IN BUILDINGS IS A FEASIBLE STRATEGY

In the Direct Use Gas Scenarios, space heating and water heating in buildings continue to be provided by pipeline gas, using a mixture of fossil natural gas and renewable natural gas, and in one scenario, a limited amount of renewably-produced hydrogen. These pathways are consistent with a future world that achieves an 80 percent reduction in GHG emissions by 2050. All of the scenarios evaluated here rely on technology innovation in producing and delivering renewable fuels at an industrial scale, this is true to a higher degree in the Direct Use of Natural Gas Scenarios. Compared to the electric heat pump pathways, maintaining gas heat in buildings doesn't require as many changes from consumers: no need for widespread investments and retrofits to existing buildings' space conditioning systems and water heaters or changes to contractor practices. The Gas Furnace Scenario assumes that consumers continue to purchase efficient versions of the same technologies for space heating and water heating that they already use.

The Natural Gas Heat Pump scenario envisions a more substantial change in how buildings are heated, through the use of natural gas heat pumps, but offers the potential for larger energy efficiency gains relative to the Gas Furnaces scenario. A further benefit of the 'drop-in' fuel feature of the Direct Use Gas Scenarios is that they avoid the need for the new electric sector infrastructure associated with meeting winter peak demands in the Building Electrification Scenarios.

The primary challenge associated with maintaining gas heat in buildings in a deeply decarbonized future is around the development and commercialization of new, low-carbon technologies: renewable natural gas, industrial electrification, renewable hydrogen and/or natural gas heat pumps. Since these scenarios use a relatively high share of the region's 2050 GHG emissions budget in the buildings sector, more mitigation efforts in other sectors of the economy are required, each of which face their own set of implementation challenges. In both of the Direct Gas Use scenarios, industry electrification is the primary mitigation measure to offset the additional emissions from the building sector. Industry electrification is an emerging opportunity for decarbonization, but more research is needed to understand the cost of industrial fuel switching.

In addition, the Direct Use Gas scenarios rely on about 30% more sustainable, carbon-neutral biofuels than the other scenarios. Research, development and investments will be needed to bring significant new quantities (between 255 and 263 tBtu by 2050)[20] of renewable natural gas and other sustainable biofuels to market. Finally, biomethane must be paired with either natural gas heat pumps or renewable hydrogen in these scenarios, neither of which are currently commercially prevalent technologies in the region. This list of technology challenges also presents a set of research, development, deployment and market transformation opportunities for NW Natural and other companies to invest in bringing to market.

5.1.2 SWITCHING TO ELECTRIC HEAT IN BUILDINGS IS A FEASIBLE STRATEGY

Building electrification, when paired with very low-carbon electricity, can displace nearly all emissions in the buildings sector using existing technologies, reducing the need for other mitigation strategies such as industrial electrification, renewable natural gas, or hydrogen. However, switching to electric heat in buildings also comes with its own challenges and risks.

Large-scale electrification of buildings depends on a transformation of the building HVAC and water heater market, accompanied by consumer acceptance and rapid adoption of electric heat pumps in place of gas equipment. In many existing homes, retrofitting to electric space heating and water heating may require expensive retrofits. Further, the building simulations and electricity sector modelling in this analysis indicate that, from a grid perspective, consumers should install cold-climate systems that perform well in cold weather to avoid the highest system-wide cost impacts to the electric grid. However, the cold-climate systems are currently more expensive than conventional electric heat pumps.

No matter what type of heat pumps are installed, the Building Electrification scenarios add large new weather-dependent loads to the Northwest Electricity system, estimated at 20,000 and 40,000 MW of

[20] In the building electrification scenarios the quantity of sustainable biofuels in 2050 is lower, at 191 tBtu.

incremental peak capacity needs by 2050. Those loads will require an expansion of the region's electric system, including additional generation, transmission and distribution infrastructure.

5.1.3 SCENARIO COSTS AND UNCERTAINTIES

Given the many uncertainties in projecting future technology costs, it appears that within a reasonable cost uncertainty range, three of the four scenarios evaluated in this analysis have similar total economy-wide costs: The Gas Furnace Scenario, the Natural Gas Heat Pump Scenario, and the Cold Climate Heat Pump Scenario. The Electric Heat Pump scenario is the highest cost scenario of the four evaluated, based on the relatively poor performance of the conventional heat pumps in cold weather.

5.1.4 POLICY IMPLICATIONS AND ONGOING RESEARCH NEEDS

Energy efficiency is critical in all scenarios

All scenarios depend on energy efficiency to enable emissions reductions at manageable costs, in buildings, industry and the transportation sector. Building shell measures reduce the annual amount of heat demanded by buildings, which is important for reducing the total cost of the Direct Use Gas Scenarios, given that there is a limited supply of carbon-neutral biomethane available. If natural gas demands were higher, then more expensive fuels like hydrogen or synthetic natural gas would be needed to meet the emissions target. Likewise, deep energy efficiency retrofits in buildings are important in reducing the total costs of the electrification scenarios because they reduce the peak heating requirements of space-heating in the region. Absent building shell improvements, the peak load impacts of electric heat pumps would be more pronounced than modeled here.

All scenarios rely on widespread electrification of the region's transportation sector

The transportation sector is currently the largest source of emissions in the Northwest. All scenarios in this analysis assume near-complete electrification of passenger vehicles by 2050, as well as high levels of truck and freight electrification. As the cost of light-duty electric vehicles declines, the deployment of public charging infrastructure will become increasingly important, particularly for those drivers who do not own their home and cannot install home-based EV chargers.

Given rapid declines in battery costs, electrification of trucks is an emerging strategy for freight transportation and was the primary decarbonization strategy assumed for trucks in these scenarios. Hydrogen fuel cell trucks represent an alternative technology pathway, but these were assumed to be higher cost than the electric options. Finally, advanced biofuels, such as renewable compressed natural gas trucks or hybrid trucks running on renewable CNG or renewable diesel represent alternative decarbonization strategies. In these scenarios, since biofuels are assumed to be relatively limited, advanced biofuels were used for aviation (renewable jet fuel) and in the gas pipeline, rather than for cars and trucks.

Advanced biofuels, such as renewable natural gas and renewable jet fuel, are needed in all mitigation scenarios

Both scenarios rely on advanced, carbon-neutral biofuels to displace remaining liquid and gaseous fuels in the economy. Oregon has already begun to promote advanced biofuels with its Clean Fuels Program. Expanding the region's policy to promote development of biomethane resources could be a worthwhile next step. It will be important to continue to refine estimates of the lifecycle emissions of biofuel resources, to ensure that they are indeed carbon-neutral resources. Using today's biofuel's technologies, the lifecycle emissions of ethanol, for example, can be comparable to fossil fuels. A transition away from current forms of biofuels, towards more sustainable, carbon-neutral biofuels is needed.

Focus research, development and deployment of space heating technologies that address or mitigate peak heat needs

This study suggests that continued use of the natural gas distribution system is a cost-effective strategy to meet the region's climate goals while also reliably serving winter peak demands. Advanced heat pump technologies could play an important role in decarbonizing heat in the Northwest at relatively low societal costs. The natural gas heat pumps modelled in this analysis are not yet commercially available in the Northwest, but NEEA staff indicate that the technology is expected to be available by the mid-2020s. In the interim, pilot programs and demonstrations would be very useful in validating the performance characteristics of natural gas heat pumps assumed in this report. Beyond 2025, market transformation and deployment programs will be needed to ensure the technology is available throughout the region.

In addition, cold-climate electric heat pumps with electric resistance back-up could provide winter heating services in the region. Cold climate heat pumps remain a relatively new technology but are available in the market today. From a societal perspective, cold climate heat pumps are preferable to standard electric heat pumps, but also have a higher upfront cost. Further, the benefits of cold-climate heat pumps will only be realized if HVAC contractors are trained and incentivized to install heat pumps that perform up to their rated efficiency, while minimizing the reliance on electric resistance supplemental heat. This implies a market transformation initiative is needed alongside ongoing technology development if widespread electrification of space heating were pursued.

A potential way to partially mitigate the peak load requirements of electrifying space heating load is to shift loads from peak to off-peak periods. Load flexibility is included in this analysis primarily through the assumption that light-duty electricity vehicles can be charged during off-peak periods. It is possible that, given the right price signals, additional electric sector load flexibility could be realized, for example, with flexible use of heat pump water heaters. However, water heaters represent only 7% of total electric loads in the Electrification scenarios, in 2050. Additional study is needed to characterize those resources' availability and costs.

Whether served by natural gas or electricity there could also be additional flexibility in buildings' heating systems. For instance, a combination of tighter shells and pre-heating of buildings could smooth morning peak loads. Alternatively, on-site heat storage systems could provide a similar service. Another source of flexibility could be hybrid electric and natural gas or propane heating systems. Those types of systems use an electric heat pump for the bulk of annual heating requirements but switch to natural gas or propane back-up during relatively cold hours[21]. These systems have the greenhouse gas benefit of displacing most fossil gas combustion, while also taking advantage of the large existing pipeline gas system as an energy storage system. Each of these alternatives comes with an incremental cost; this study did not attempt to evaluate how much these alternatives might cost relative to the incremental electricity sector expansion costs identified in this analysis.

Overall, this study focused on the economics of a deep decarbonization from a societal perspective. As a next step, it would be helpful to develop a better understanding of the consumer economics and consumer choices that may drive the adoption of different space heating technologies in the Pacific Northwest.

Strategies to deploy industry electrification and hydrogen electrolysis

A more granular characterization of the region's industrial sector could help decision-makers understand: 1) in what industries and end-uses in the Pacific Northwest a shift from fossil fuels to electricity is most plausible and, 2) what policy mechanisms would be most conducive to incentivizing a shift of the region's industrial sector towards electrification.

[21] These systems are being evaluated in Europe, see for example Wales and West Utilities 2018

Finally, renewably-produced hydrogen from electrolysis is a small portion of the energy used in the Gas Furnace Scenario, but it helps to close the emissions gap to meet the 2050 GHG goal. This scenario assumes that up to 6% hydrogen by energy, about 20% by volume, can be blended into the existing pipeline gas supply without a need for upgrades to end-use equipment or the region's gas transmission, storage and distribution systems. Further study of the impacts of hydrogen on those systems would be a valuable next step.

Many pathways exist to achieving decarbonization in the Pacific Northwest. The challenge lies in the development and sustained deployment of the advanced technologies needed to transform the region's energy economy over the next two to three decades.

6 Appendix

6.1 Baseline Key Drivers of Pathways Model Energy Demands

Sector	Key Driver	Compound annual growth rate [%]	Data Source
Residential	Housing Units	1.15%	NWPCC Projections
Commercial	Square Footage	1.11%	NWPCC Projections
Industry	Energy growth	Varies by fuel	EIA AEO 2018 growth rates 2017-2050
Industry	Natural Gas Energy growth	0%	NW Natural
On Road Transportation	VMT	0.35% average 2015-2050	State DOT forecasts
Off Road Transportation	Energy growth	Varies by fuel	EIA AEO 2018 growth rates 2017-2050
Electricity generation	Electric load growth	0.77% average 2015-2050	Built up from Pathways demands in Buildings, Industry, Transportation

6.2 Reference Scenario Key Assumptions

	Reference Scenario
Electricity generation	
Carbon-free generation	20% Weighted RPS target in 2040 (per 50% Oregon RPS requirement by 2040 and 15% Washington RPS by 2020) and85% Carbon-free by 2050
Buildings	
Energy Efficiency	50% of appliance sales are high-efficiency by 2030, reflecting NWPCC 7th Power Plan
Transportation	
Zero-Emission Vehicles	8% sales by 2025, 20% light-duty sales by 2030 (5% PHEV, 15% EV)
Efficiency	Federal CAFÉ standards for LDVs by 2026
Biofuels	
Conventional Biofuels	10% ethanol blend in gasoline (currently 7% E85 and 93% E10)
Other Sectors	
Energy Consumption	Grows at AEO 2017 reference scenario growth rates by fuel
Non Combustion GHG Emissions	Held constant at current GHG Inventory levels

6.3 Mitigation Scenario Key Assumptions

	Gas Furnace Scenario	Electric Heat Pump Scenario
Electricity generation		
Carbon-free Generation	97% Carbon-free by 2050	95% Carbon-free by 2050
Buildings		
Energy Efficiency	100% of appliance sales are high-efficiency by 2030 100% adoption of efficient building shell/weatherization measures by 2030	
Sales of Heat Pump Equipment	100% heat pump sales replacing electric resistance by 2040. 100% efficient gas furnaces by 2030	100% heat pump sales replacing electric resistance by 2040. 60% heat pump by 2030, 98% by 2050
Transportation		
Sales of Zero-Emission Vehicles	LDVs: 70% by 2030, 100% by 2050 MDVs: 85% by 2030, 85% through 2050 HDVs: 60% by 2030, 80% by 2050	
Efficiency	Federal CAFĖ standards for LDVs through 2026, Aviation efficiency of 40% below Reference Scenario by 2050	
Biofuels		
Advanced Biofuels	Advanced biofuels from wastes, residues and purpose grown crops, sourced from within the PNW region	Advanced biofuels from wastes, residues and purpose grown crops, sourced from within the PNW region (20% less than gas scenarios)
Other Sectors		
All Emissions	Reduction of 80% below 1990 Levels	
Industry Electrification	30% of Industry End Uses electrified by 2050	5% of Industry End Uses electrified by 2050

	Gas Heat Pump Scenario	Cold Climate Heat Pump Scenario
Electricity generation		
Carbon-free Generation	97% Carbon-free by 2050	95% Carbon-free by 2050
Buildings		
Energy Efficiency	100% of appliance sales are high-efficiency by 2030 100% adoption of efficient building shell/weatherization measures by 2030 100% sales of ductless heat pumps in place of resistance by 2040	
Sales of Heat Pump Equipment	20% Natural Gas HP sales by 2030, 100% by 2050	60% Cold Climate HP sales by 2030, 98% by 2050 (small amount of electric resistance in Commercial)
Transportation		
Sales of Zero-Emission Vehicles	LDVs: 70% by 2030, 100% by 2050 MDVs: 85% by 2030, 85% through 2050 HDVs: 60% by 2030, 80% by 2050	
Efficiency	Federal CAFÉ standards for LDVs through 2026, Aviation efficiency of 40% below Reference Scenario by 2050	
Biofuels		
Advanced Biofuels	Advanced biofuels from wastes, residues and purpose grown crops, sourced from within the PNW region	Advanced biofuels from wastes, residues and purpose grown crops, sourced from within the PNW region (30% less than gas scenarios)
Other Sectors		
All Emissions	Reduction of 80% below 1990 Levels	
Industry Electrification	30% of Industry End Uses electrified by 2050	5% of Industry End Uses electrified by 2050

6.4 Building Simulations and Evaluation of Electric Heat Pump Winter Peak Performance

This study focuses on the role of buildings in achieving the broader economy-wide deep decarbonization goal. Buildings contribute to GHG emissions through both consumption of electricity generated from fossil fuels and through direct, or on-site use of fossil fuels. The primary purpose of direct use of gas in buildings is to provide heat.

Space-heating loads are the largest source of natural gas use in buildings in the Northwest, followed by water-heating, cooking and clothes drying—in that order. Space heating loads are also weather dependent. As the outdoor air temperature drops, buildings require more heat to maintain a comfortable temperature for occupants. Today, space heating energy needs in the Northwest are met by a combination of natural gas (68%), electricity (24%), petroleum products (6%) and wood (2%).

The relatively high share of electric resistance space-heating in the region, combined with mild-summers, means that the region has historically seen the highest electricity demands in the winter, [22]The PNUCC estimates that the winter peak for the Northwest in 2019 will be 36.4 GW, while summer peak is forecasted at 35.2 GW.

The heating requirements of buildings increases and the output of electric air-source heat pumps decreases as the outdoor air temperature drops. When a heat pump can no longer provide sufficient heat to maintain a comfortable temperature of building occupants, supplemental heat is required. The most common type of supplemental heat installed is electric resistance. Where a heat pump may have a COP of over 2 or higher in cold temperatures, an electric resistance element has a COP of 1. Supplemental heat

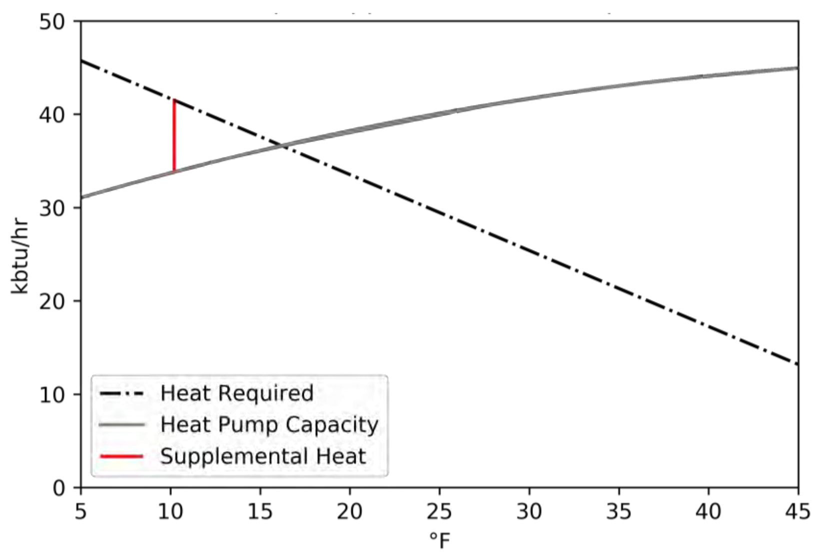
[22] The increased adoption of air conditioning in the region – which is nearly 100% electric – means that the summer peak is now catching up to the winter electric demand. The results of this study show that with electrification of a majority of non-electric space heating load that the region would become a heavily winter peaking region.

fills the gap between a buildings heating requirements and a heat pump's output until a 'lockout' temperature is reached, after which point only supplemental heat is used.

Buildings require the most space-heating energy during morning hours when there is little solar radiation and thermostats are set to daytime settings. Peak space-heating loads tend to occur during the coldest morning hours of the year. However, some years have lower minimum morning temperatures than others.

The amount of supplemental electric resistance heat required depends on the capacity of the heat pump and the heating load of the building. Figure 34 compares the maximum output of the 4-ton cold-climate heat pump simulated by Big Ladder to the hourly heating requirements of the median NW Natural residential customer. As the temperature drops the heat pump requires more input power per unit of useful heat produced. When the heat pump can no longer provide enough heat to heat the home—when the grey line is below the dotted black line—supplemental electric resistance heat is needed.

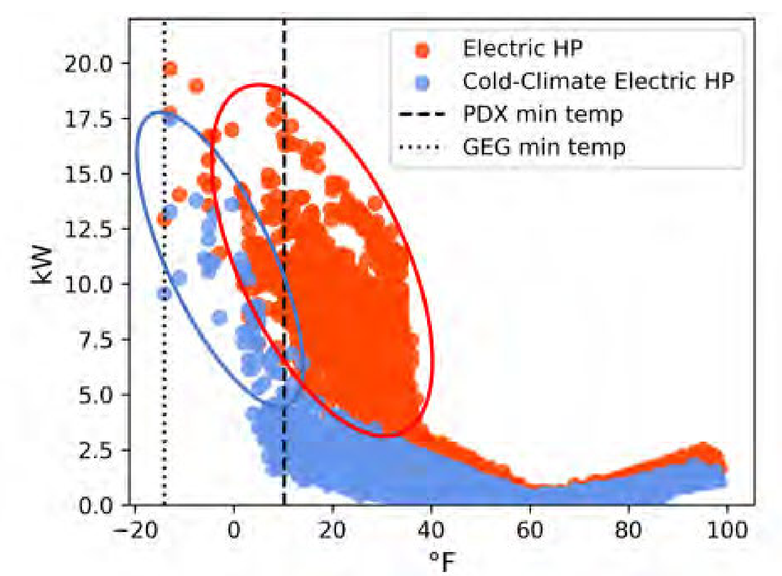
Figure 34: Air-source heat pumps and supplemental heat



The building simulations in this analysis show that supplemental electric resistance heat can markedly increase the load of homes served by cold-climate electric heat pumps. The share of electric resistance heat in the building simulation increases as the temperature drops. In the Portland simulations, a 4-ton ducted heat pump provides 34 kbtu/hr at 10.2°F, the coldest simulated temperature, but the building requires 42 kbtu/hr to stay warm. The gap between the heat pump's output and building heating demand is filled by 8 kbtu/hr of supplemental heat, equivalent to over 2.3 kW of additional electric load. The amount of energy required for the heat pump itself also increases as the temperature drops, with its COP dropping from 4 annually to 2.5 during the coldest hour simulated. The result is a combined load for the HVAC system—the heat pump, electric resistance heater and fans— of over 7 kW at 10.2°F.

Figure 35 shows HVAC demand over the same 8760 hours of weather in the representative year for both the conventional and cold-climate heat pumps simulated in EnergyPlus. The figure includes loads simulated for both Portland and Spokane. The conventional electric heat pump simulations (red) lock-out the heat pump compressor below 34°F,[23] relying entirely on electric resistance heat below that temperature. These results represent an estimate for the load impacts of electrifying space-heating in the Northwest with commonly installed systems today. The cold-climate heat pumps (blue) show a marked improvement in performance as the temperature drops. However, loads for these systems begin to increase more rapidly as the temperature drops below 20° Fahrenheit. This is especially true during the early morning heating hours when solar gains are at their minimum and homes recover from their night-time setbacks.

Figure 35. Simulated heat pump performance by temperature



Big Ladder also simulated the performance of a cold-climate heat pump in a smaller home, comparing its hourly load with that of a conventional electric furnace. The heat pumps in these homes also require supplemental heat at temperature below 18° Fahrenheit but exhibit a large improvement in performance

[23] The Energy Trust of Oregon provides a heat pump control incentive to new and existing heat pumps ($250) to set the lockout temperature at 35°F ("or as close as possible"). https://www.energytrust.org/wp-content/uploads/2016/09/HES_FM0320C.pdf

relative to a stand-alone electric furnace. Where conversions of gas homes to electric heat pumps create new electric loads, replacing electric resistance heat with an efficient electric heat pump puts downward pressure on peak loads.

6.4.1 FROM BUILDING SIMULATIONS TO SYSTEM-WIDE BUILDING LOAD SHAPES

Electrification of gas homes causes incremental annual and peak loads. The peak load in a typical Northwest gas home would be nearly 7kW during a '1 in 10 year' winter cold-snap. East of the Cascades, where temperatures can drop below -10°F during a very cold winter, that figure rises to over 13kW per home. However, the cumulative electric-sector loads in a high electrification future depend on a variety of different factors, including:

- The amount of electric resistance heat displaced;
- The diversity of space-heating loads in the region; and
- Improvements in the thermal efficiency of buildings.

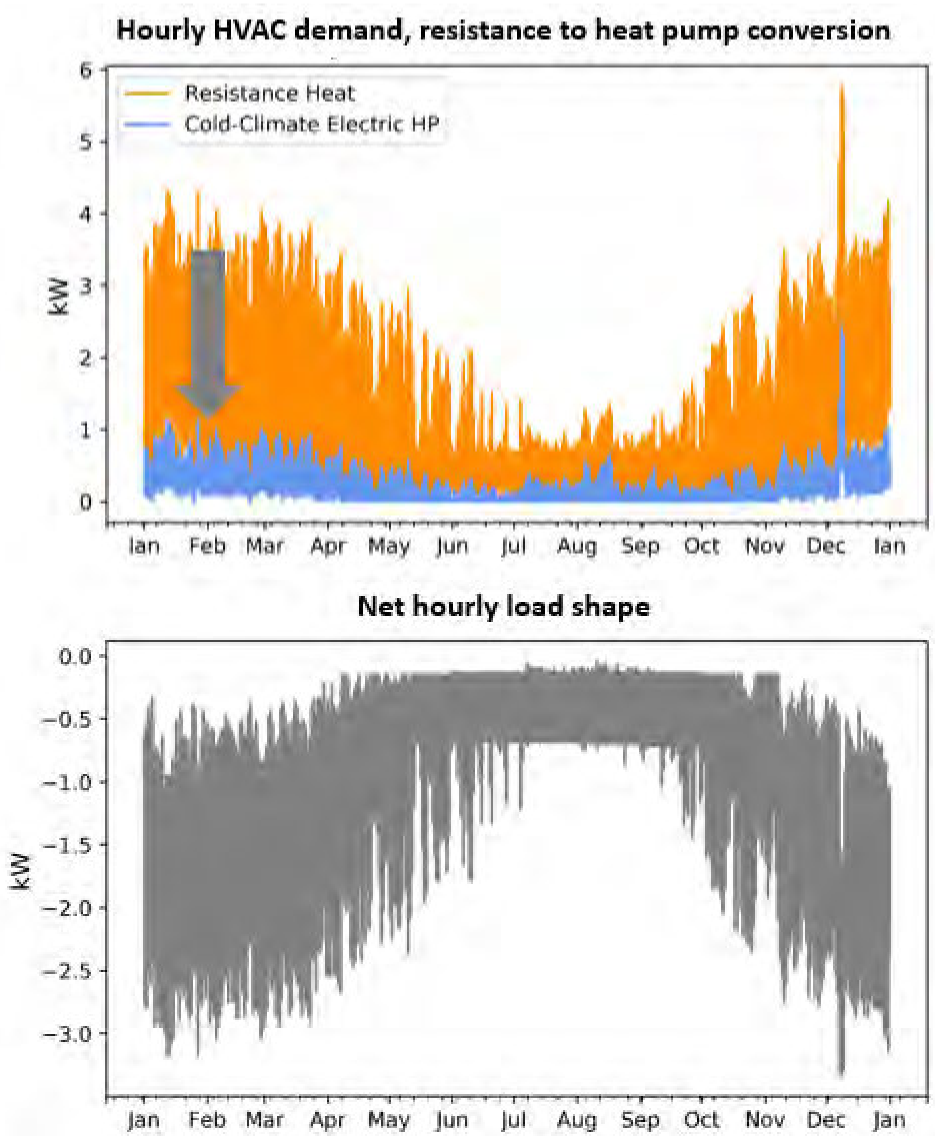
This study accounted for all three of these factors when defining electric-system peak loads in all of the mitigation scenarios, resulting in appreciably lower peak load estimates than if these adjustments were not made.

Displaced electric resistance heat

The Northwest has high levels of existing electric resistance heat relative to other moderate to cold climates in the country. High levels of electric resistance heat contribute to the region's current winter electric sector peak. A key assumption made in this analysis is that most electric resistance heat in the region is replaced with electric air-source heat pumps. Electric resistance heat in the smaller housing units[24] save over 6 MWh in annual load and, importantly, also puts downward pressure on peak load. Building simulation results for the small single-family home during the coldest hour, show a peak savings of almost 3.5 kW (Figure 36).

[24] In the Pacific Northwest electric resistance heat is most commonly installed in multifamily housing units like apartment complexes, manufactured homes, and small single family homes.

Figure 36: Displaced electric resistance heat



Diversity of space heating loads across the region

No individual building load shape is an accurate representation of the system load that must be served by the electricity system. We consider two mechanisms through which diversity could occur for space-heating loads: 1) a behavioral effect, and 2) spatial variation of weather.

Behavioral diversity in space-heating loads occurs because occupants of buildings choose to heat their homes and businesses at different times. Diversity from spatial variation of weather occurs because the minimum temperatures will vary across population centers in the Northwest. For instance, during the '1 in 10' cold-snap simulated in this analysis, the temperature is almost 6 Fahrenheit warmer in Seattle than Portland during the coldest hour simulated in the latter city.

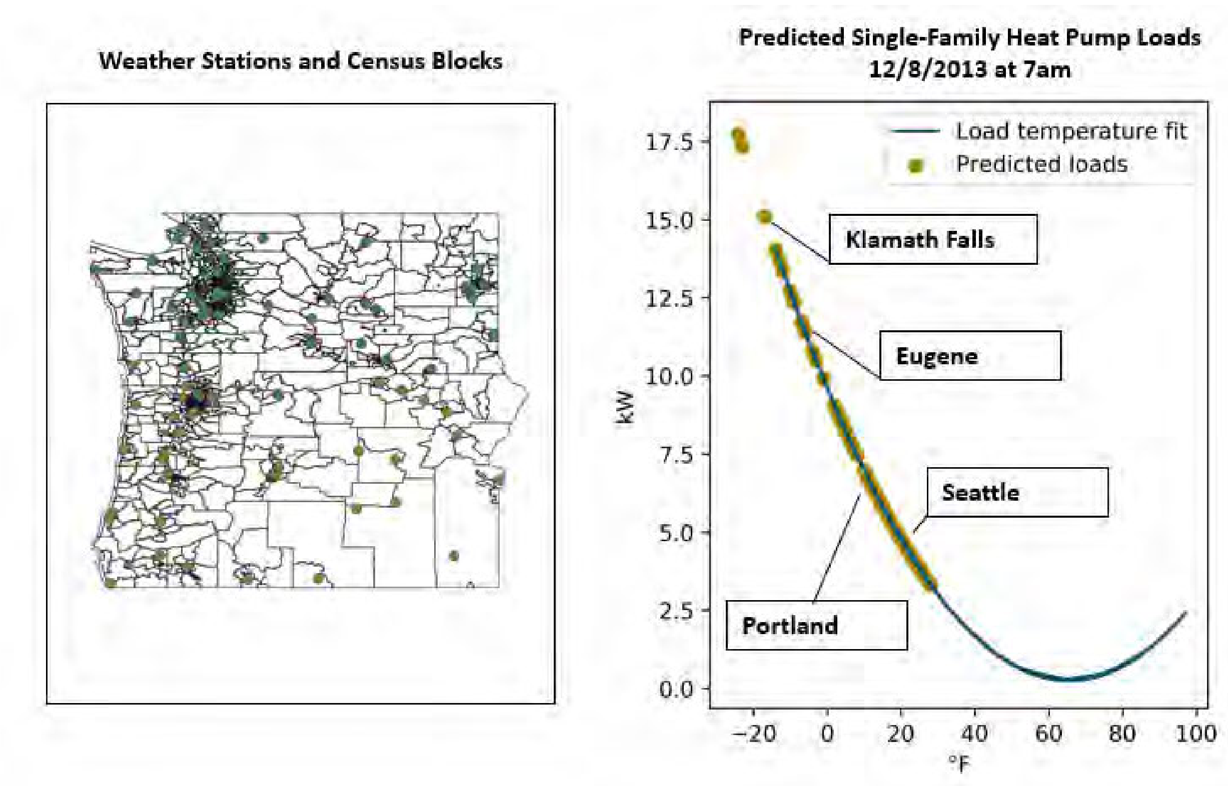
We account for behavioral diversity in the building simulations via two mechanisms. First, EnergyPlus returns electric loads on an hourly basis, so the hourly peak demand (kW) figures reported in this analysis are averaged hourly loads (KWh/h), not the instantaneous peak load for each building. A building simulation that provided heating estimates in shorter intervals would return higher peak values per building than those returned from EnergyPlus. However, variations in loads between hours also occur for behavioral reasons. Building heating is related to the behavioral choices and patterns of occupants. As a result, some buildings will start heating relatively early in the morning and some relatively late (Hanmer et al 2018). E3 and Big Ladder accounted for between hour variations in heating by allowing two hours for the simulated heat pump systems to meet the morning thermostat temperature[25] for each building. This modelling decision smooths out the morning heating period, lowering the peak load during the 7am hour compared to model results that only allow 1 hour to meet the morning thermostat set point.

E3 evaluated the potential for geographic diversity using a combination of the EnergyPlus load shapes, and temperature data from 76 airport weather stations in Oregon and Washington. Weather station data were paired with American Community Survey (ACS) estimates of where gas homes in each state are

[25] Representative thermostat heating setpoints were developed from the NEEA RBSA, and fall between 67.4- and 68.7-degrees Fahrenheit, depending on building type.

located. An hourly load shape for each weather station was estimated by using the relationship between HVAC load and temperature identified in EnergyPlus (Figure 37). This relationship was developed by fitting a 2^{nd}-order polynomial to the temperatures and loads in Energy Plus during the 7am peak morning heating hour. Using that fit, a peak load was estimated for each fuel-switching single-family home in the region at 7am on December 8, 2013—the hour that drives peak planning requirements in this analysis.

Figure 37: Load diversity in Oregon and Washington



The average peak load for gas homes east and west of the Cascades simulated in Energy Plus during that hour was 6.8 kW. However, Washington was warmer than Oregon during that peak hour. As a result, the predicted loads using weather station data for Washington are 5.2 kW per home. In contrast, Oregon as a whole was colder than the temperatures simulated in Energy Plus during the peak heating hour. After accounting for the colder temperatures elsewhere in Oregon, the predicted average load per home for Oregon is 7.8 kW, or 1 kW higher than the figure returned by Energy Plus. There are more gas homes in Washington than Oregon, so the weighted average peak load per home using weather station data is 6.1 kW per home. We use the ratio of those weather-matched predicted loads and Energy Plus simulated loads as an estimate of weather-driven load diversity factor. That factor, equal to 0.9, decreases the peak capacity requirements associated with space-heating electrification by 10%.

Energy efficiency and weatherization

Peak heating requirements in buildings are driven by heat loss. One important strategy to reduce the annual and peak heating loads in buildings is to increase the ability of buildings to retain heat. Measures to weatherize a building might include installing more insulation, sealing bypasses, adding storm doors and replacing windows. In general, it is easier to install these measures in a new building, avoiding expensive retrofit costs. We assume that every new building has an efficient shell and that a substantial number of existing buildings undergo a retrofit. Accomplishing wide-spread retrofits will be a major challenge but is a critical measure for any strategy to reduce heat related GHG emissions.

PATHWAYS treats building shell improvements as a ‘stock’ measure that flows through the model like any other building equipment. Building shells are assumed to have a lifetime of 40-years. Effectively, this means that buildings undergo a major retrofit every 40-years, at which point a suite of weatherization measures are installed. An ‘efficient’ building shell in PATHWAYS decreases both the annual and peak heating requirements of buildings by 40%, and in 2050 73% of buildings are assumed to have an efficient shell. That is equivalent to 100% of new buildings being built with an efficient envelope and 60% of existing buildings receiving a retrofit. In sum, building shell measures reduce both annual and peak heating requirements in the region by 30% compared to loads that would have occurred without the measures.

6.5 Other End Use Load Shape Assumptions

Transportation Electrification Load Shapes

Electric vehicle charging load profiles are based on an EV charging model which translates travel behavior into EV load shapes by weekday/weekend, charging strategy, and charging location availability. This travel behavior is based on the 2009 National Household Transportation Survey, a dataset on personal travel behavior[26]. This study assumes that 60% of drivers have charging infrastructure available at home and work by 2050, while the rest have charging infrastructure available only at home. Furthermore, we let RESOLVE dynamically charge a certain percentage of cars that are plugged in; this is constrained by the number of cars that are plugged in, the instantaneous driving demand for that hour, and how much charge capacity is available. By 2050, 100% of electric vehicle charging is assumed to be flexible when plugged in. In 2050, this means that 100% of light duty electric vehicles flexibly charge outside of business hours, while 60% of light duty electric vehicles charge flexibly during business hours. This means that electric vehicles contribute very little to peak demand needs, despite increasing total electricity demands.

Hydrogen Electrolysis Load Shapes

In this study, hydrogen electrolysis facilities operate flexibility in RESOLVE, and thus avoid operating during system peak hours. While hydrogen electrolysis contributes significantly to total electricity demand in the Gas Furnaces scenario, it has no impact on incremental peak load. However, hydrolysis loads do spur additional renewable energy capacity expansion as additional solar resources are developed to provide

[26] http://nhts.ornl.gov/introduction.shtml

enough zero-carbon energy to power the hydrolysis and stay within the 3 MMtCO2e electric sector emissions budget for that scenario.

Industrial Load Shapes

Incremental industrial electrification loads are assumed to have a load shape that reflects the system-wide loads before electrification. This simplification was used because industrial loads are heterogenous in terms of both their base shape, their ability to be flexible and there is not sufficiently detailed public data available to translate annual electrification to a net change in annual electricity demands. There is reason to believe that much of this load could be flexible, however, given that most of the industrial load assumed to be electrified in these scenarios is currently served by natural gas; and the majority of natural gas industrial load in NW Natural's service territory elects to be on interruptible schedules. Interruptible schedules are a form of demand response where customers receive a discount on their rate for the option to be interrupted – or required to stop using gas – during peak cold events.

Electrified HVAC shapes will, insofar as they equate to air-source heat pumps, increase peak load requirements during cold weather. Other processes may be flexible, decreasing the capacity impacts of industry electrification. The Gas Scenarios have higher industry electrification levels than the Electric Heat Pump Scenarios and the incremental peak impact of industry in electrification in those scenarios is approximately 2 GW. While the exact capacity impact of industry electrification deserves further study, the order of magnitude does underscore the difference between electrifying more- and less-weather-dependent loads.

Water heating

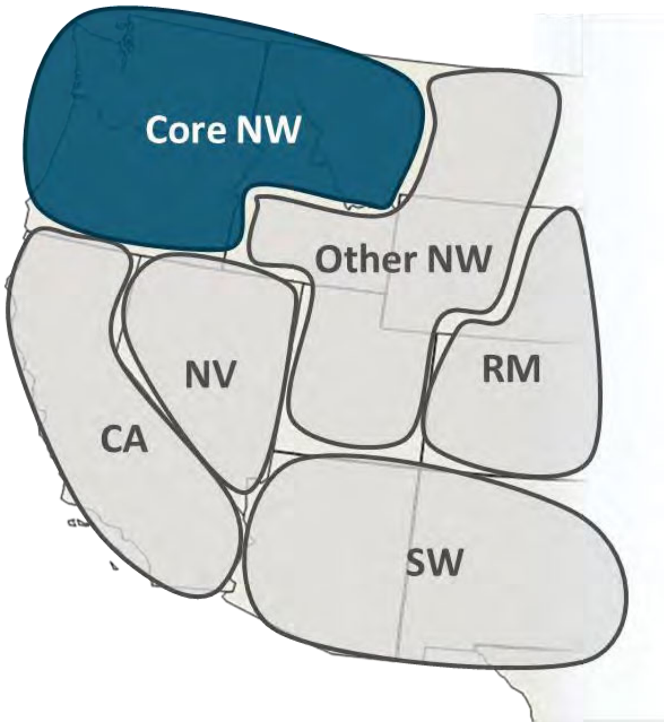
In addition to space heating electrification, we investigate the effect of water heating electrification on system peak. As part of a multi-year field metering study done on behalf of NEEA, Ecotope, Inc. created annual hourly load profiles for electric resistance and electric heat pump water heaters (Ecotope 2014).

Ecotope, Inc. developed representative shapes from 135 sites, encompassing a variety of installation locations, equipment brands, and climates. The day of week and time of year, in addition to hour of day, significantly affect water heating load. The change in water heating load over the year is affected by ground water temperature, which changes much more slowly than air temperature, and thus the daily air temperature is less impactful on water heating load shapes than on space heating load shapes. To incorporate the Ecotope calculated water heater load profiles into a system wide load shape, we match water heater load shapes from Ecotope with the day of week and month of year for the subset of days modeled in RESOLVE.

6.6 State cost results

The Northwest PATHWAYS model developed for this analysis models Oregon and Washington as two distinct regions of energy demand. Electricity supply in RESOLVE is modelled on a regional basis. RESOLVE costs were downscaled to each state by their 2017 load share of the “Core NW” region modelled in RESOLVE (Figure 38).

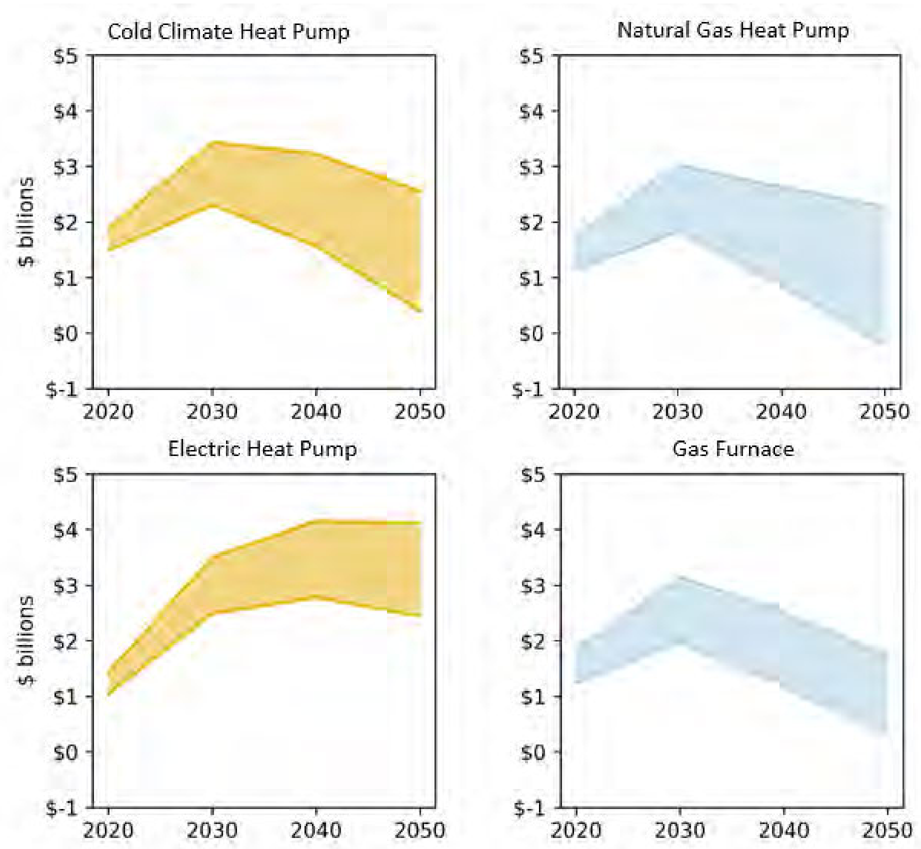
Figure 38: RESOLVE foot print



6.6.1 OREGON

Costs in Oregon are generally lower than those in Washington. This is partially due to Oregon being small relative to Washington. However, costs in Oregon are also proportionally lower relative to the Reference case because the state has lower biofuels demands than Washington. In fact, the lower bound of 3 of 4 mitigation scenarios in Oregon are near or below $0 incremental costs Figure 39.

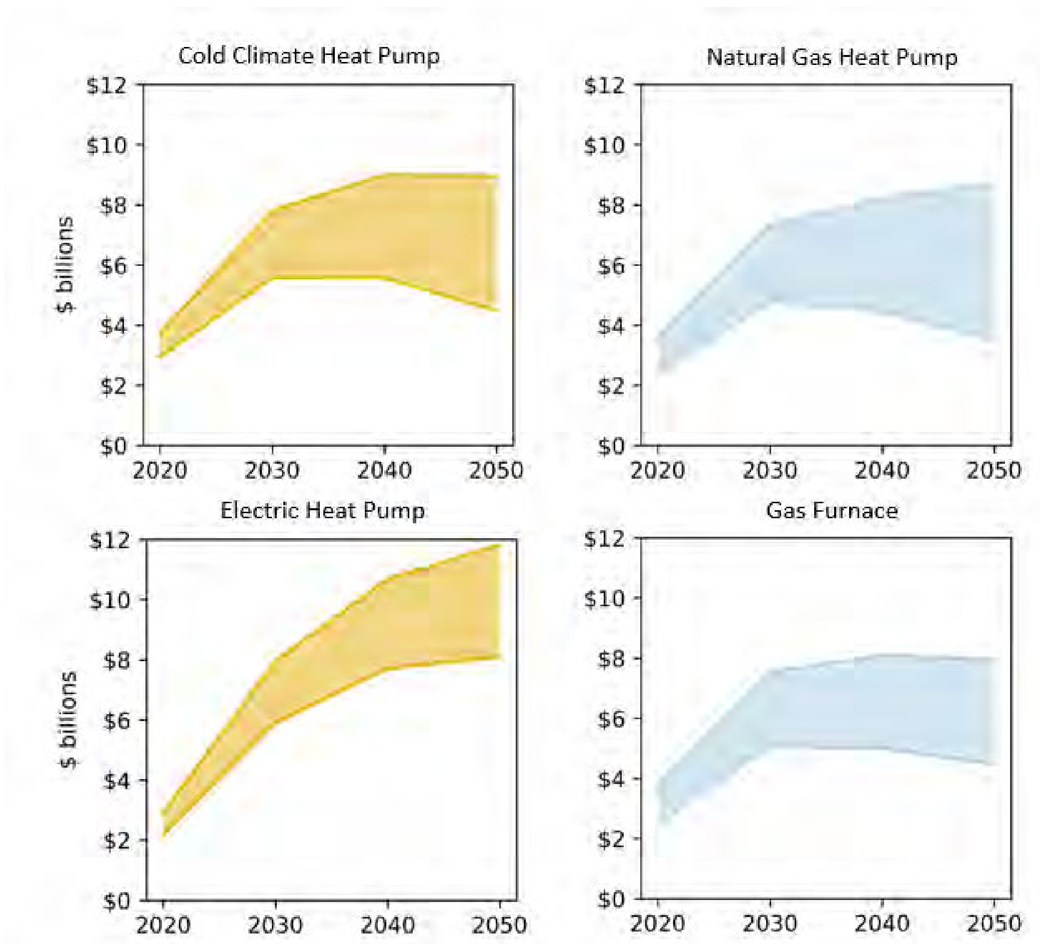
Figure 39: Scenario Costs in Oregon



6.6.2 WASHINGTON

Costs in Washington are higher than Oregon (Figure 40). These costs are partially driven by Washington having a larger energy economy than Oregon, though an additional driver of the cost differentials across scenarios are higher biofuels demands in Washington. Those higher biofuels demands are almost entirely attributed to Washington's aviation emissions. After aviation efficiency measures, the PATHWAYS model allocates a large share of the region's available biomass to displace remaining jet kerosene demands. Washington's emissions inventory includes per-capita aviation emissions above 1.1 MtCO2e. Per-capita aviation emissions in the Oregon inventory are approximately 0.5 MtCO2e, and nationally per-capita aviation emissions were 0.68 MtCO2e per person.

Figure 40: Scenario costs in Washington



6.7 Key data sources

6.7.1 GROWTH RATES AND DRIVERS

Sector	Key Driver	Compound annual growth rate	Data Source
Residential	Housing Units	1.15%	NWPCC Projections
Commercial	Square Footage	1.11%	NWPCC Projections
Industry	Energy growth	Varies by fuel	EIA AEO 2018 growth rates 2017-2050
Industry	Natural Gas Energy growth	0%	NW Natural
On Road Transportation	VMT	0.35% average 2015-2050	State DOT forecasts
Off Road Transportation	Energy growth	Varies by fuel	EIA AEO 2018 growth rates 2017-2050
Electricity generation	Electric load growth	0.77% average 2015-2050	Built up from Pathways demands in Buildings, Industry, Transportation
Fossil fuel price forecasts	$/GJ	Varies	EIA AEO 2018 growth rates 2017-2050

TECHNOLOGY COSTS

Technology	Source
Building heating equipment	Energy Trust of Oregon (ETO 2016) National Energy Modelling System (USDOE 2018) Northwest Energy Efficiency Alliance (NEEA 2016, 2018) National Renewable Energy Laboratory Efficiency Measures Database (NREL 2018)
Other building equipment (e.g. lighting, refrigeration, etc...)	National Energy Modelling System (USDOE 2018)
Battery electric vehicles	National Energy Modelling System (NEMS 2018) Ricardo Electric Vehicle Cost Forecast as Appendix C to PG&E EPIC DC Fast Charging Mapping Report (PG&E 2016)
Battery electric trucks	National Energy Modelling System (NEMS 2018) National Renewable Energy Laboratory Electrification Futures Study (NREL 2017)
Biofuels	United States Department of Energy Billion Tonnes Study (US DOE 2016)

Technology	Source
Hydrogen	UCI Advanced Power and Energy Program 2018 CEC Long-term Strategic View of the Use of Natural Gas in California. Publication Forthcoming
Electric sector	Public Generation Pool Carbon Study (PGP/E3 2017)
Electricity sector costs	PGP Carbon Study (E3 2017) Northwest Power and Conservation Council 7th Plan (NWPCC 2016)

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1703

June 6, 2022

American Gas FOUNDATION

January 2021

Building a Resilient Energy Future:

How the Gas System Contributes to US Energy System Resilience

An American Gas Foundation Study Prepared by:

Guidehouse

Background and Methodology

This study was conducted to investigate the resilience of the US gas system and the ways in which the gas system contributes to the overall resilience of the US energy system. This work was directed to ask and answer four key questions:

- What are the characteristics of the US gas system that contribute to its resilience?
- How do those resilience characteristics allow the US gas system to contribute to the overall resilience of the US energy system?
- How can the US gas system be leveraged more effectively to strengthen the US energy system?
- What are the policy and regulatory changes that may help ensure that gas infrastructure can be maintained and developed to continue to support energy system resilience?

These questions were explored through a qualitative assessment conducted by Guidehouse, including discussions and interviews with many energy industry subject matter experts. Case studies and examples of resilience were identified as a part of these discussions. Guidehouse used these studies and examples to develop a framework for considering the resilience of the US gas system and to identify barriers and opportunities related to the gas system's role in supporting the resilience of the US energy system. The findings presented in this work identify issues that merit consideration and further exploration when developing future energy policy and regulation to ensure a resilient, reliable, and clean future energy system in all regions and jurisdictions.

Disclaimers

American Gas Foundation

Founded in 1989, the American Gas Foundation (AGF) is a 501(c)(3) organization focused on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. When it comes to issues that impact public policy on energy, the AGF is committed to making sure the right questions are being asked and answered. With oversight from its board of trustees, the foundation funds independent, critical research that can be used by policy experts, government officials, the media and others to help formulate fact-based energy policies that will serve this country well in the future.

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Abbreviations

Abbreviation	Definition
AGF	American Gas Foundation
AWIA	America's Water Infrastructure Act
Bcf	Billion Cubic Feet
Btu	British Thermal Units
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAISO	California Independent System Operator
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CNG	Compressed Natural Gas
DSM	Demand Side Management
Dth	Dekatherm
EIA	US Energy Information Administration
ESR	Energy Storage Resources
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HVAC	Heating, Ventilation, And Air Conditioning
ISO	Independent Service Operator
ISO-NE	Iso New England Inc.
LCOE	Levelized Cost of Electricity
LDC	Local Distribution Company
LNG	Liquified Natural Gas
KWh	Kilowatt-Hour
MMcf	Million Cubic Feet
MMcfd	Million Cubic Feet Per Day
MMBtu	Million British Thermal Units of Natural Gas
MW	Megawatt
MWh	Megawatt-Hour
NASA	National Aeronautics and Space Administration
NERC	North American Electric Reliability Corporation
NGV	Natural Gas Vehicle
NOAA	National Oceanic and Atmospheric Administration
NJNG	New Jersey Natural Gas
NYISO	New York Independent System Operator
OBA	Operational Balancing Agreement
PGE	Portland General Electric
psi	Pounds Per Square Inch
PSPS	Public Safety Power Shutoff
PUC	Public Utility Commission
PV	Photovoltaic
RNG	Renewable Natural Gas
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
US	United States
UTMB	University of Texas Medical Branch

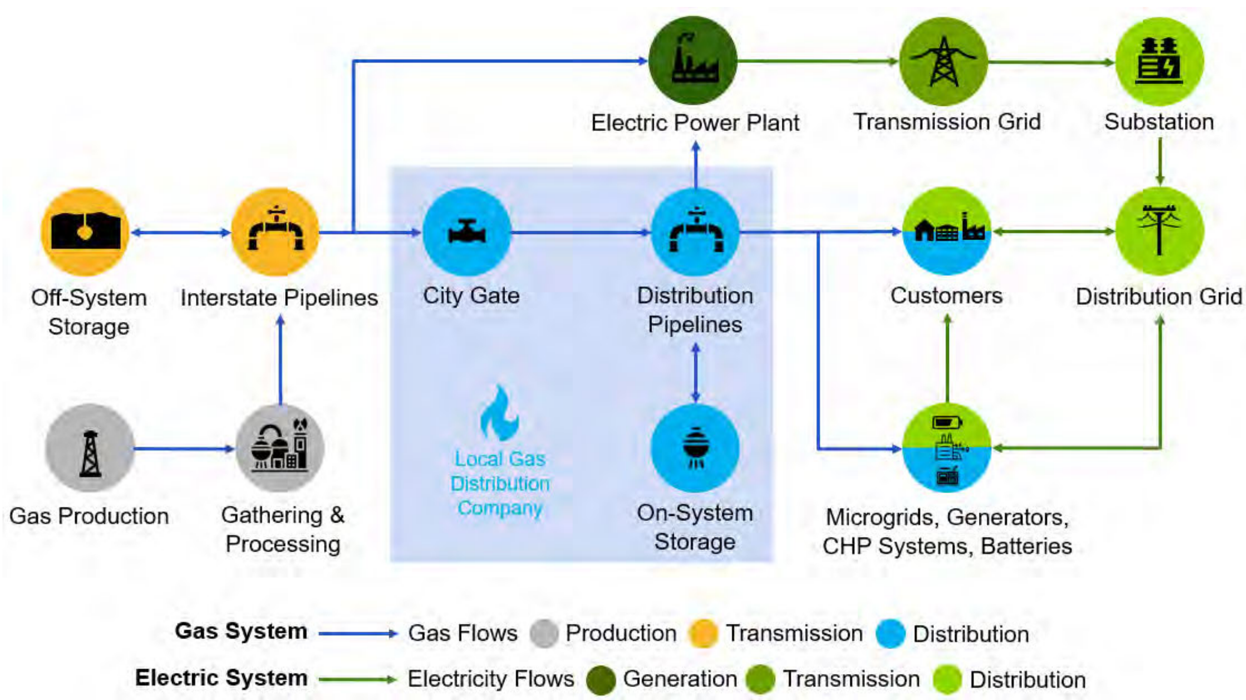
EXECUTIVE SUMMARY

A resilient energy system is essential to the operation of nearly every critical function and sector of the US economy as well as the communities that depend upon its services. Disruptions to the US energy system create widespread economic and social impacts, including losses in productivity, health and safety issues, and—in the most extreme cases—loss of life. As utilities, system operators, regulators, and policymakers deliberate the design and structure of the future energy infrastructure, they must consider the resilience of the entire energy system. As the transformation of the energy system accelerates, it is important for stakeholders to understand the increasing interdependence of gas and electric systems and their role in creating a more resilient future.

A Primer on the Energy System

An energy system is defined as the full range of components related to the production, conversion, delivery, and use of energy. Energy in the US can take many forms; this report focuses on the natural gas system, herein referred to as the gas system, and its interdependencies with the electric system (Figure 1).

Figure 1. Interdependencies Between the Gas and Electric Systems



Source: Guidehouse

What Is Resilience?

Resilience is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. Resilience is defined in relation to a high-impact, low-likelihood events. The most common examples of these events are extreme weather events (which go beyond standard hot days or snowstorms) of a size and scale to cause significant operational disruption, system damage, and devastating societal impacts. Recent resilience events that affected the US energy system include the 2020 California heat waves, Hurricane Isaias, and the 2019 Polar Vortex.

> *Resilience and reliability are often referenced together, but they reflect critical differences in system design and operation.* ***Resilience*** *is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event such as a major disruption in a transmission pipeline. In comparison,* ***reliability*** *refers to a systems' ability to maintain energy delivery under standard operating conditions, such as the standard fluctuations in demand and supply.*

The increasing frequency and severity of climatic events amplifies the need to maintain the resilience of the US energy system. System resilience is gained through diversity and redundancy. The resilience of the US energy system is increased through evolving and holistic management of the gas and electric systems, valuing each of their unique characteristics. To ensure resilience, the energy system needs pipeline delivery infrastructure and storage capabilities meeting both short- and long-duration needs.

The nation's gas system is a critical resource for addressing resilience threats to the overall energy system. This report examines how the characteristics of the US natural gas system enable energy reliance today and opportunities to effectively use the gas system to achieve future energy resilience.

Resilience Characteristics of the Gas System

The gas system supports the overall resilience of the energy system through its inherent, physical, and operational capabilities (Figure 2) that enable it to meet the volatile demand profiles resulting from resilience events.

Figure 2. Resilience Characteristics of the Gas System

Inherent Resilience of Gas	Physical Resilience of Gas System Assets	Operational Resilience of the Gas System
A molecular form of energy storage; the natural gas molecule is an abundant energy form with long-duration and seasonal storage capabilities.	Most gas system assets are underground and shielded from major disruptions. In most cases, the system is self-reliant, reducing its exposure to disruption.	Operational flexibility is designed into the gas system within a set of system standards that ensure the system's safety and security.

• Compressibility
  ○ Storage
  ○ Linepack
• Abundance and Diversity of Supply
	• Underground infrastructure
	• Looped and Parallel T&D Network
	• Self-Reliant Gas-Fired Equipment
	• Distributed Customer Generation
	• System Storage Capacity
		• Robust Management Practices
		• Flexible Delivery
		• Demand Side Management
		• Large Customer Contract Design

Source: Guidehouse

Resilience in Action

Large, catastrophic failures of the energy system have been few and far between—the energy system has performed well, overcoming periods of high stress that have threatened its resilience. These high stress events are becoming more frequent due to the increase in the frequency and severity of extreme weather events associated with climate change. To successfully build for the future and invest in the right set of resilience solutions, it is important for stakeholders to understand how the energy system has performed under recent resilience events.

Recent climate events have revealed the US energy system's potential vulnerabilities. However, the multitude and diversity of resilience assets that already exist as part of the energy system have made the difference—facilitating energy flows to critical services and customers. As the following case studies illustrate, the resilience assets that are part of the gas system have supported the overall integrity of the energy system during these high stress periods.

2019 Polar Vortex

In 2019, the Midwest experienced record-breaking cold temperatures, which led to increased demand on the energy system to meet heating needs.

- CenterPoint Energy curtailed gas service to interruptible customers and pulled gas from every possible storage resource to maintain service to homes and businesses. In one day, CenterPoint delivered almost 50% more than a standard January day.
- On January 30, 2019, Peoples Gas, North Shore Gas, and Nicor Gas together delivered gas in an amount equivalent to more than 3.5 times

	the amount of energy that ComEd, the electric utility serving an overlapping territory has ever delivered in a single day. • The Consumers Energy's Ray Compressor Station fire on January 30 took a primary storage supply resource offline. Consumers leveraged several gas resilience characteristics (linepack, backup storage, and a highly networked gas system) to ensure that no critical, priority, or residential customer lost service.
2014 Polar Vortex	During early February 2014, a polar vortex brought extreme cold temperatures, snowfall, and high winds to Oregon. On February 6, during the system peak, NW Natural set a company record for natural gas sendouts, which still stands today. Nearly 50% of this peak demand was met by natural gas storage capacity. In combination with diligent planning and dedicated employees, this case study highlights the critical role that natural gas storage plays in meeting demand during extreme weather events.
2020 Hurricane Isaias	On August 4, 2020, Hurricane Isaias made landfall in North Carolina. It caused significant destruction as it moved north, triggering electric outages that affected more than 1 million New Jersey homes and businesses. Many customers experiencing electric outages turned on their natural gas backup generators, resulting in a massive increase in demand for New Jersey Natural Gas (NJNG). In 24 hours, NJNG experienced a 60% increase in daily demand on its gas system—the daily demand for this one day was higher than any other August day for the previous 10 years. Because of the built-in storage capacity (compressibility and on-system storage) and flexibility of the gas system, NJNG was able to ramp up service to customers with disrupted electricity supply.
2020 Heat, Drought, and Wildfires	In August 2020, California was in the middle of its hottest August on record,[1] a severe drought, and its worst wildfire season in modern history. Concurrent to increased demand on the electric system driven by increased cooling loads, California also experienced a decrease in renewable output (due to smoke from the fires)[2] and lower imports than had been anticipated by electric supply planners. To meet increased electric demand, system operators turned to gas-fired generation facilities. During the week of August 11, all of SoCalGas' system storage assets were employed to fill the gap between abnormally high electric demand and low renewable energy generation experienced in Southern California.

In all of these case studies, the gas system provided significant support to the energy system in maintaining resilience and ensuring that energy service was maintained to customers. To understand the gas system's contribution to resilience, it is important to differentiate between the pipeline infrastructure system and the natural gas molecules that flow through it. The gas pipeline system is defined as a series of physical assets that transport energy molecules from the source of production to end users, including residential, commercial, and industrial customers who use gas in their buildings and processes, and electric generators who use gas to

[1] NOAA. *National Climate Report*. August 2020.

[2] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO*. September 30, 2020.

make electricity. Today, the gas system is used to transport mostly geologic natural gas, but it can be leveraged to transport low-carbon gases such as renewable natural gas (RNG) and potentially hydrogen in the future as utilities move to decarbonize the energy system.

The Growing Resilience Challenge

Driven by changes in the cost and availability of new technologies and increasing political and social pressure to decarbonize, our energy system is undergoing a transformation. This transformation exposes an issue of energy system resilience related to the interaction of the gas and electric systems.

> *As the percentage of electricity generation from intermittent renewable sources increases, the volume of natural gas used for electric power generation may decline; however, in responding to resilience events the necessity of the services provided by gas-fired electric generators may increase. As current compensation models for the gas system serving the power generation sector are tied to the volume of gas delivered to the facility, there becomes an increasing disconnect between the value of the services provided and associated remuneration for said services.*

To further highlight the need for energy system resilience as part of the current transformation, it is worth considering a recent review of the root cause of the California Independent System Operator (CAISO) electric outages during the August 2020 heatwave. One of the three factors identified was: "In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet [electric] demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm."[3]

The current model for maintaining the resilience of our energy system was built to support a legacy view of how the energy system operates. As an example, natural gas infrastructure replacement and modernization programs were designed to enhance reliability and safety. As noted in this report they have also contributed to resilience. As the transition to the future energy system accelerates, it is important to understand how these programs complement future energy state resilience needs. The manner in which this energy system is regulated and managed is becoming outdated, and an update is necessary to maintain resilience of the evolving future energy system.

Ensuring a Resilient Future Energy System

The increasing frequency and intensity of climatic events combined with the transformation of the energy system to one increasingly powered by intermittent renewable sources establish the need for a new consideration of the resilience of the energy system. Utilities, system operators, regulators, and policymakers need to recognize that resilience will be achieved through a diverse set of integrated assets—for the foreseeable future, policies need to focus on optimizing the characteristics of both the gas and electric systems.

[3] CAISO. *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm*. 2020.

Achieving this is easier said than done. It will require a realignment of the valuation and cost recovery mechanisms that currently define the development of the US energy system:

- Energy system resilience must be defined as a measurable and observable set of metrics, similar to how reliability is considered.
- Resilience solutions must be developed considering all possible energy options and across utility jurisdictions, requiring electric, gas, and dual-fuel utilities to work together to determine optimal solutions.
- Methodologies need to be built to value resilience, such that it can be integrated into a standard cost-benefit analysis. Value should consider the avoided direct and indirect costs to the service provider, customers, and society.

The resilience of the current energy system is largely dependent on the gas system’s ability to quickly respond to events and use its extensive long-duration storage resources to meet peak and seasonal demand. Ensuring future energy system resilience will require a careful assessment and recognition of the contributions provided by the gas system. Utilities, system operators, regulators, and policymakers need new frameworks to consider resilience impacts to ensure that resilience is not overlooked or jeopardized in the pursuit to achieve decarbonization goals.

1. Introduction

A resilient energy system is essential to the operation of nearly every critical function and sector of the US economy—and the need for energy system resilience is only increasing as emergency services, communications, transportation, banking, healthcare, water supply, and other critical systems become more interconnected than ever. Disruptions to the US energy system can have widespread economic and social impacts, including losses in economic productivity, health and safety issues, and—in the most extreme cases—loss of life.

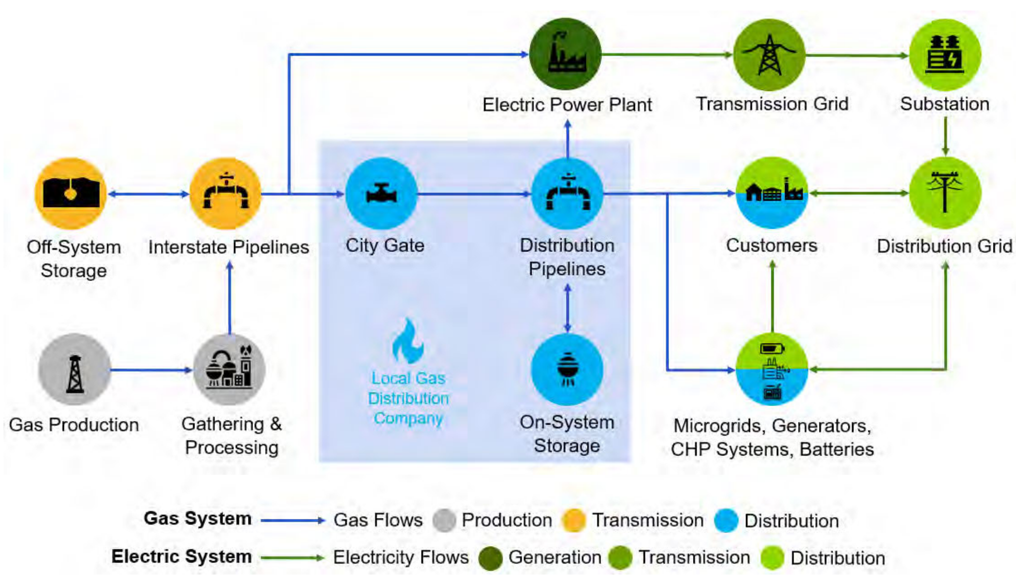
This report examines the resilience of the current gas system with a focus on the part of the system that is under the operational control of the gas local distribution company (LDC). It also examines how the gas system contributes to the resilience of the overall energy system. The work was directed to ask and answer four key questions:

1. What are the characteristics of the US gas system that contribute to its resilience?
2. How do those resilience characteristics allow the US gas system to contribute to the overall resilience of the US energy system?
3. How can the US gas system be leveraged more effectively to strengthen the US energy system?
4. What are the policy and regulatory changes needed to ensure that gas infrastructure can be maintained and developed to continue to support energy system resilience?

1.1 A Primer on the Energy System

An energy system is defined as the full range of components related to the production, conversion, delivery, and use of energy. Energy takes many forms; this report focuses on the natural gas system, herein referred to as the gas system, and its interdependencies with the electric system (Figure 1-1).

Figure 1-1. Interdependencies Between the Gas and Electric Systems

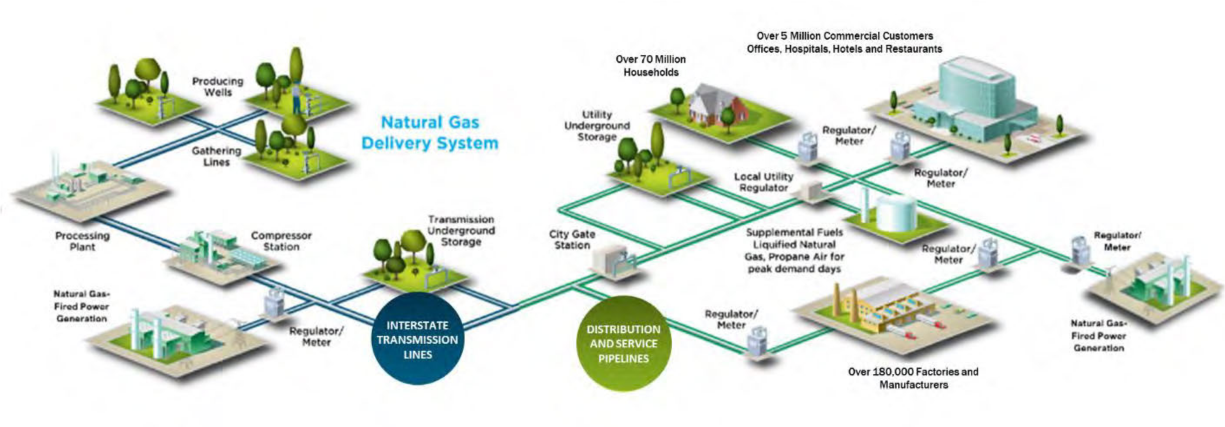


Source: Guidehouse

The gas system is the series of assets that transport energy molecules from the source of production to the site of consumption. The customers served by this system include residential, commercial, and industrial buildings and processes; gas-fired electric generation facilities; transportation fuel providers; and natural gas exporters.

Today, the gas system is used to transport mostly geologic natural gas and small amounts of renewable natural gas (RNG). In the future, the gas system can be leveraged, with only small upgrades, to transport a low carbon fuel supply including RNG, hydrogen, and synthetic methane.

Figure 1-2. Overview of the Gas System



Source: American Gas Association

The gas system can generally be divided into three sections (Appendix A presents further details):

1. **Production and Processing:** Encompasses the process of gathering the gas and treating it to remove impurities.
    - Wells extract natural gas primarily from geologic shale formations.
    - Gathering pipelines transport gas to processing facilities where impurities are removed.
    - Compressors move the gas through midstream pipelines to the connection with interstate transmission pipelines.

2. **Transmission:** Includes the network of high-pressure transmission lines that transport gas from supply basins to market demand centers and, in some cases, across local gas LDC systems.
    - Compressor stations are located approximately every 50 to 60 miles along long-haul transmission pipelines and within gas systems to regulate pressure and keep gas moving.
    - Storage assets connected to the transmission system (defined as off-system storage) exist along these transmission pipelines enabling operators to adjust flow to meet daily and seasonal demand requirements. Storage assets are either underground (i.e., depleted gas reservoirs, aquifers, or salt caverns) or aboveground (where gas is stored as LNG or CNG).

3. **Distribution:** Under the operational control of the LDC, the gas distribution system is primarily comprised of regulator stations, gas pipeline mainlines, and gas pipeline service lines that collectively reduce pressure and move gas from the transmission system to customers.

    - In many cases, gas passes through a city-gate where custody is transferred from the interstate transmission system to the LDC. At this point, gas volumes are measured, typically odorized, and pressure is reduced.
    - LDCs may have LNG, CNG, or underground storage assets on the distribution system (defined as on-system storage), allowing the LDC to maintain reliability and meet short-term demand increases.

1.2 A Primer on Resilience

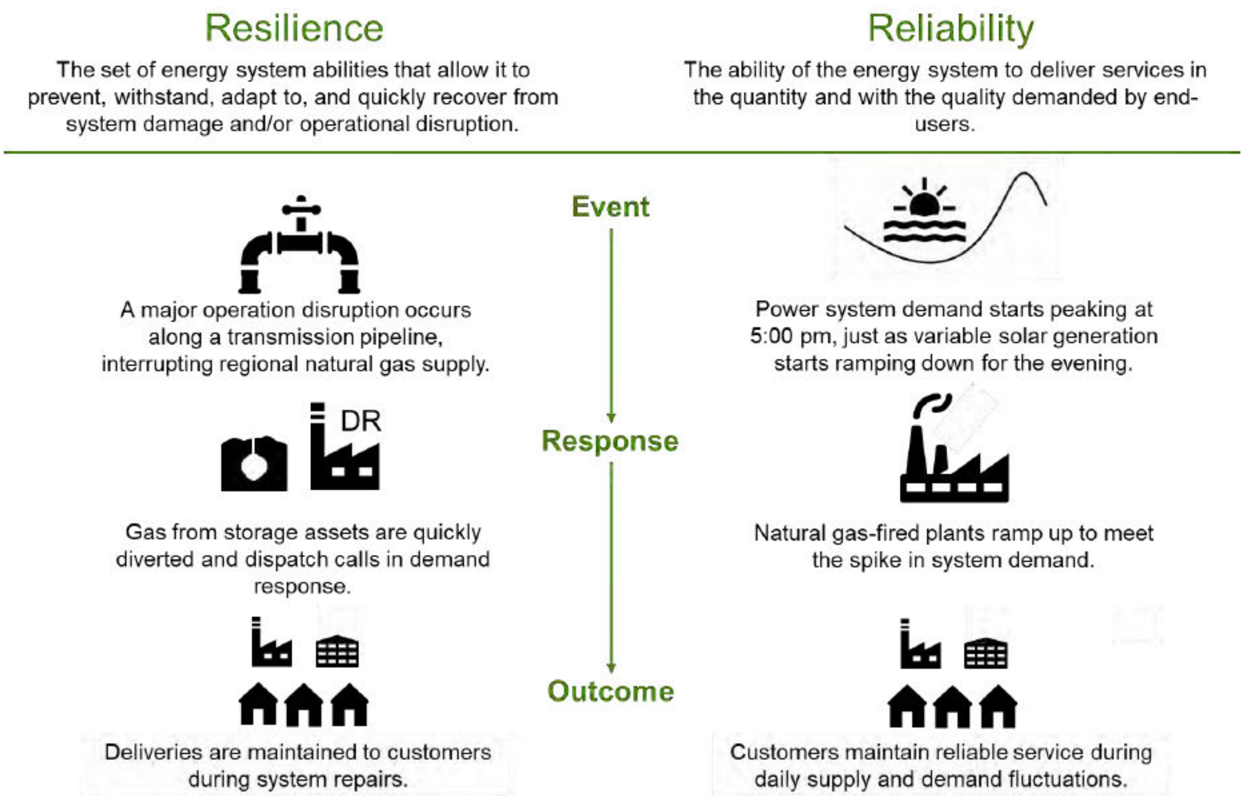
Resilience is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. The term is defined in relation to a high-impact, low-likelihood event. The most common examples of these events are extreme weather events (which go beyond standard hot days or snowstorms) of a size and scale to cause significant operation disruption, system damage, and devastating human health impacts. Common threats that test the durability of the energy system include extreme weather events (e.g., hurricanes, wildfires, and extreme heat/cold), cyberattacks (e.g., malware and cyber intrusions), and accidents.

Recent examples of resilience events that affected the US energy system include the 2020 California heat waves, Hurricane Isaias, and the 2019 Polar Vortex; each of which are explored in greater detail in Section 3. Other recent resilience events that have exposed the value of the gas system in maintaining energy system delivery include the 2017 Bomb Cyclone,[4] the 2017 Californian wildfires and landslides, Hurricane Irma, and Hurricane Harvey.[5]

Resilience and reliability are often referenced in tandem, but there is a critical difference between the terms and their impact on the design and operation of energy systems. Reliability is defined in relation to a low-impact, high-likelihood event. The US energy system manages reliability daily—in the standard fluctuations in energy supply and demand. Figure 1-3 illustrates resilience and reliability events, along with typical energy system responses and associated outcomes.

[4] The Natural Gas Council; Prepared by RBN Energy. 2018. *Weather Resilience in the Natural Gas Industry: The 2017-18 Test and Results.*
[5] ICF. 2018. *Case Studies of Natural Gas Sector Resilience Following Four Climate-Related Disasters in 2017*.

Figure 1-3. Comparison of Resilience and Reliability

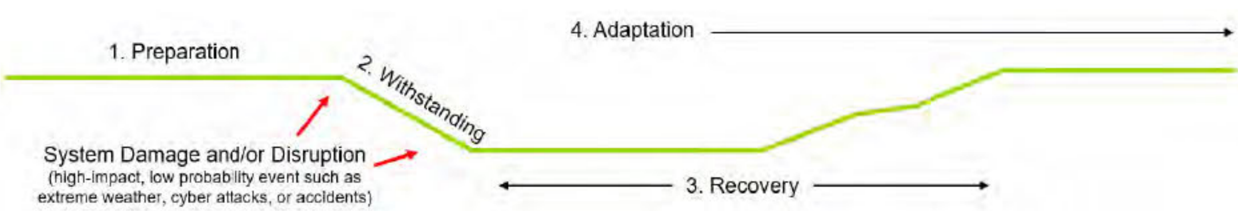


Source: Guidehouse

One way to conceptualize a resilience event is to separate it into distinct phases, where each phase is defined by a time period in relation to the event's onset. Figure 1-4. illustrates this approach with a resilience curve. Table 1-1Table 1-1. defines the four phases of this curve: preparation, withstanding, recovery, and adaptation.

The resilience curve provides a framework for understanding how an energy system's resilience can be strengthened. It is used in Section 2 to classify the resilience characteristics of the gas system.

Figure 1-4. The Energy System Resilience Curve



Source: Guidehouse

Table 1-1. Definition of the Phases of Resilience

Phase	Resilience Characteristics	Timeframe
1. Preparation	The ability to prepare for and prevent initial system disruption	Leading up to the disruption event

Phase	Resilience Characteristics	Timeframe
2. Withstanding	The ability to withstand, mitigate, and manage system disruption	During the disruption event
3. Recovery	The ability to quickly recover normal operations and repair system damage	Following the end of the disruption, until system functions are fully restored
4. Adaptation	The ability to adapt and take action to strengthen the energy system in face of future disruption events	Throughout, but especially during and following the recovery phase

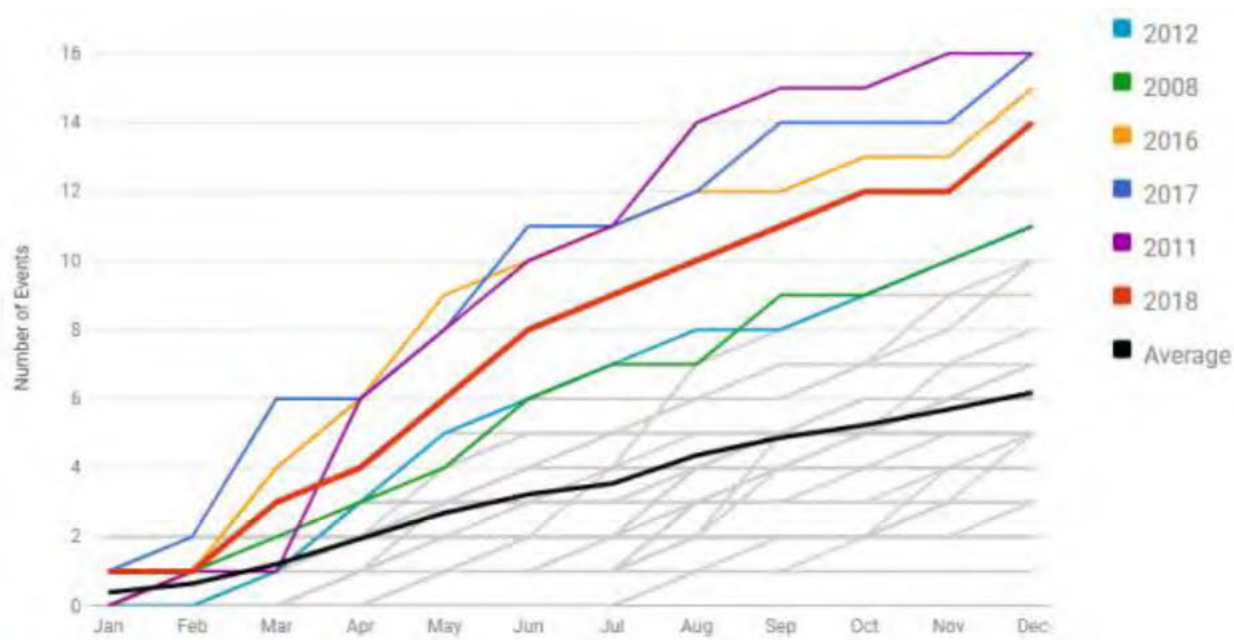
Source: Guidehouse

1.2.1 The Increasing Importance of Resilience

The increased frequency and severity of extreme weather events increasingly put the US energy system at risk. Over the last 50 years, much of the US has experienced increasingly extreme weather including prolonged periods of excessively high temperatures, heavy downpours, flooding, droughts, and severe storm activity.[6]

In the last decade, the US has experienced historic numbers of inflation-adjusted billion-dollar disasters. From 2016-2018 there were 15 billion-dollar disasters per year, up from an average of 6.2 billion-dollar disasters per year since 1980.[7] Figure 1-5. illustrates this trend and shows the cumulative inflation-adjusted billion-dollar disasters on an annual basis since 1980.

Figure 1-5. 1980-2018 Year-to-Date US Billion-Dollar Disaster Event Frequency (CPI-Adjusted, Events Statistics are Added According to the End Date)



Source: NOAA, [2018's Billion Dollar-Disasters in Context](#)

[6] NOAA. 2014. *Fourth National Climate Assessment*.
[7] NOAA. 2019. *2018's Billion Dollar Disasters in Context*.

To further highlight the importance of placing focus on the resilience of the energy system, consider California in August 2020. California was in the middle of its hottest August (record warmest in 126 years),[8] a severe drought, and its worst wildfire season in modern history. These weather events resulted in increased demand on the electric system, driven by increased cooling load. Concurrently, the state was experiencing a decrease in the anticipated electricity supply from hydroelectricity imports and solar electric generation due to smoke from the wildfires.[9] The coincidence of these events resulted in a significant gap between electricity demand and supply on the California system that led to rolling blackouts on August 14 and 15.[10]

As explored in Case Study 3, in Section 3, because the gas system filled a considerable portion of the gap between abnormally high electric demand and low renewable energy generation, Southern California avoided catastrophic failure.

The increasing frequency and severity of climate events amplify the need to maintain and strengthen the resilience of the US energy system. The energy system needs redundancy and storage capabilities to respond to dramatic shifts in supply and demand quickly.

1.3 An Orientation to this Report

The remaining content in this report is separated into five major sections.

- *Section 2 The Resilience of the Gas System* describes the various inherent, physical, and operational characteristics of the gas system that contribute to the resilience of the US energy system.

- *Section 3 Proving It: Resilience in Action* details five case studies that demonstrate how gas distribution companies across the country have demonstrated gas system resilience through real-world examples.

- *Section 4 Current Regulatory, Policy, and Market Structure* summarizes how current regulatory, policy, and market structures create challenges for building gas resilience assets.

- *Section 5 Ensuring A Resilient Future* explores how decarbonization-driven changes to the electric system may present challenges for future resilience and lessons learned from other economic sectors.

- *Section 6 Conclusions* presents a call to action for how the findings in this report can be used and their implications for policymakers and regulators.

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[8] NOAA. National Climate Report – August 2020. https://www.ncdc.noaa.gov/sotc/national/202008

[9] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO.* September 30, 2020. https://www.eia.gov/todayinenergy/detail.php?id=45336

[10] California Independent System Operator. 2020. *Preliminary Root Cause Analysis.*

2. The Resilience of the Gas System

This section explores the fundamental resilience characteristics of the gas value chain and describes how it provides resilience services to customers. These characteristics are detailed further in Section 3 in case studies that demonstrate gas system resilience through real-world examples.

2.1 Fundamental Resilience Characteristics of the Gas System

Guidehouse examines the fundamental inherent, physical, and operational characteristics of the gas system in relation to their contribution along the resilience curve phases, i.e. how they help the gas system prepare for, withstand, recover from, and adapt to a resilience event. Table 2-1 outlines the key questions considered in evaluating these characteristics within the gas value chain.

Table 2-1. Key Questions Used to Identify Resilience Characteristics

Resilience Phase	Key Identifying Questions
1. Preparation	• Does it help the system prepare for or prevent threats? • Does it reduce the physical exposure of system infrastructure to the threat?
2. Withstanding	• Does it help minimize system impacts or sensitivity to potential disruptions? • Does it help prevent the occurrence of cascading failures? • Does it help the system maintain functioning if a disruption occurs?
3. Recovery	• Does it assist in restoring or repairing lost functionality?
4. Adaptation	• Does it help the system adjust to changing climate or operating conditions? • Does it facilitate learning and resilience investments to prevent future threats?

Source: Guidehouse

Gas system characteristics that contribute to energy system resilience are highlighted in Figure 2-1. they are also discussed in greater detail throughout this section.

Figure 2-1. Resilience Characteristics of the Gas System

Inherent Resilience of Gas	Physical Resilience of Gas System Assets	Operational Resilience of the Gas System
A molecular form of energy storage; the natural gas molecule is an abundant energy form with long-duration and seasonal storage capabilities.	Most gas system assets are underground and shielded from major disruptions. In most cases, the system is self-reliant, reducing its exposure to disruption.	Operational flexibility is designed into the gas system within a set of system standards that ensure the system's safety and security.

• Compressibility
  ○ Storage
  ○ Linepack
• Abundance and Diversity of Supply
	• Underground infrastructure
	• Looped and Parallel T&D Network
	• Self-Reliant Gas-Fired Equipment
	• Distributed Customer Generation
	• System Storage Capacity
		• Robust Management Practices
		• Flexible Delivery
		• Demand Side Management
		• Large Customer Contract Design

Source: Guidehouse

2.2 Inherent Characteristics of Gas Resilience

As a molecular form of energy storage, natural gas molecules have several inherent characteristics that contribute to the resilience of the gas system. Chief among these characteristics is its compressibility, which allows additional volumes of gas to be packed into the pipeline or under- and above-ground storage. Natural gas supply is also abundant and geographically diverse, allowing it to meet current energy needs even in the event of a supply chain disruption. The inherent characteristics also hold true for low carbon forms of gas supply which may replace natural gas in the future gas system. Table 2-2 summarizes the inherent characteristics of gas resilience, which are also discussed further in this section.

Table 2-2. Inherent Resilience Across the Phases of Resilience

<table>
<tr><th></th><th colspan="4">Resilience Phases</th></tr>
<tr><th>Characteristic</th><th>Preparation</th><th>Withstanding</th><th>Recovery</th><th>Adaptation</th></tr>
<tr><td>Compressibility
Storage
Linepack</td><td colspan="2">Reduces sensitivity to disruptions</td><td>Buffers against cascading failures</td><td></td></tr>
<tr><td>Abundance and Diversity of Supply</td><td></td><td colspan="2">Maintains production in the event of a regionally isolated supply-side disruption</td><td>Low carbon options for a future energy system</td></tr>
</table>

Source: Guidehouse

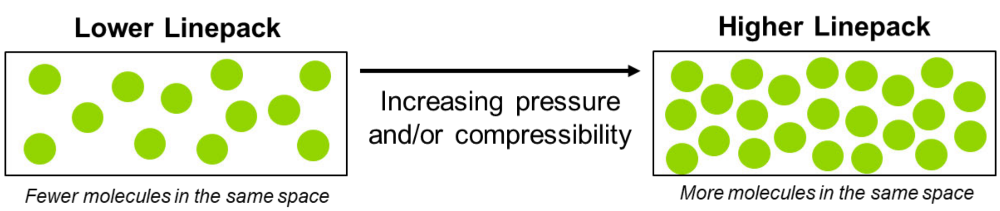
2.2.1 Compressibility

Natural gas is made up of inherently stable and compressible molecules, making it a desirable energy storage carrier and pipeline system buffer.

- **Storage** – Long-duration gas storage is frequently used to meet seasonal demand patterns and can be used as a complement to the electric system in meeting demand during low-likelihood, high-impact resilience events. Natural gas can be compressed and stored underground in geological formations (e.g., in depleted gas reservoirs, aquifers, or salt caverns) or aboveground in tanks (as LNG or CNG). As LNG, the volume of natural gas is about 600 times smaller than its gaseous form at atmospheric pressure; whereas, as CNG, it is 100 times smaller.

- **Linepack** – Excess natural gas molecules, i.e. more than what would be needed to meet customer demand can be compressed and stored within pipelines, acting as a buffer to minimize the impact of short-term hourly supply and demand fluctuations on the gas system (Figure 2-2).[11] Gas system operators, including LDCs, can control the amount of linepack in the pipes, allowing them to meet rapid, intraday changes in demand even if upstream supply is insufficient.

Figure 2-2. Linepack and Compressibility of Gas



Source: Guidehouse

Figure 2-2 provides a clear example of how linepack and storage can be used in tandem to prevent and mitigate the effects of a major gas system disruption. These characteristics are different from the electricity grid where disruptions can immediately impact all connected gas systems and increase the risk of cascading failures. Electric supply and demand must be balanced across the electric system near instantaneously and electricity can only be stored in specified storage assets, such as batteries.

2.2.2 Abundance and Diversity of Supply

Natural gas is supplied from a variety of sources across North America, including:

- **Conventional production:** Currently, natural gas is primarily produced from shale plays and formations; it is also produced in smaller quantities from conventional gas reservoirs, tight sands, carbonates, and coal-bed methane. Figure 2-3 highlights the geographic diversity of US shale plays and formations. Additionally, an evaluation by the Potential Gas Committee at year-end 2018 indicated that the US possesses a technically recoverable resource base of natural gas of nearly 3,400 trillion cubic feet (Tcf).[12] The US Energy Information Administration additionally reported that US proved

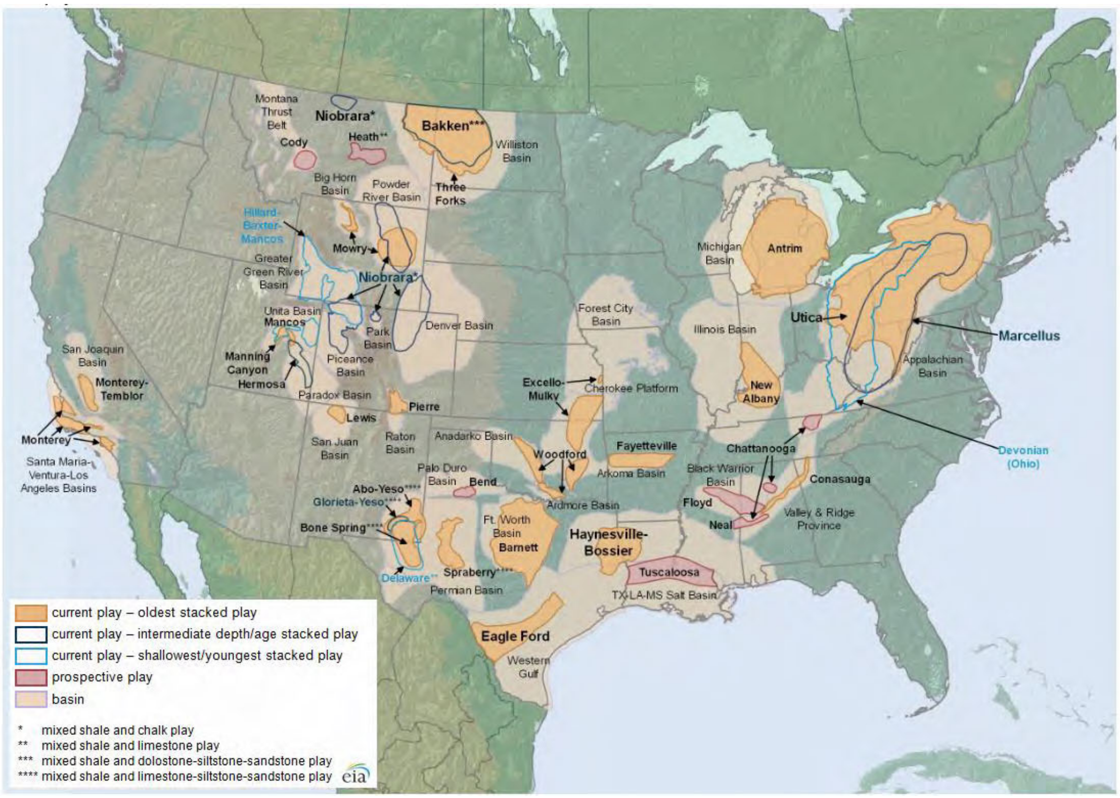
[11] Natural Gas Council. 2019. *Natural Gas: Reliable and Resilient.*

[12] Potential Gas Committee. 2019. *Potential Supply of Natural Gas in the United States.* Accessed November 2020.

reserves stood at 504.5 Tcf as of 2018. The combination of these supplies suggests a future gas supply resource enough to meet over 100 years of consumption at current levels.[13]

This abundance and diversity of natural gas supply ensures that natural gas can continue to meet customer demand even during regionally isolated supply-side disruptions such as a major storm event. For example, limited supply interruptions during recent hurricanes demonstrates the value of shifting natural gas production from the Gulf of Mexico to geographically diverse shale plays and formations.

Figure 2-3. US Shale Plays and Formations



Source: US Energy Information Administration

- **Low Carbon Production:** The abundance and diversity of resources transportable through the gas system will increase as RNG and hydrogen become increasingly commercially viable. Though it is only a small portion of current US gas supply, RNG supply is growing dramatically--produced from a variety of waste feedstocks from the sewage, agriculture, food, and forestry sectors, as detailed in Appendix B. Hydrogen is projected to serve a larger portion of future US gas demand, but it is earlier in the process of developing commercial viability in the US, though it is already flowing through the pipes in Europe as discussed in Appendix B.

[13] Natural Resources Canada. 2020. _Natural Gas Facts._ Accessed October 2020.

- **Pipeline Imports:** Natural gas is also imported via pipeline from Canada, and from elsewhere as LNG. These are critical supply sources during peak periods and lend to greater gas system flexibility.

2.3 Physical Characteristics of Gas System Resilience

The gas system's physical characteristics lend themselves to providing stability to the energy system. Most pipeline infrastructure is underground and looped, creating flexibility in a delivery system that is shielded from many major disruptive events. Much of the gas delivery system also runs on its own supply, making it self-reliant. The ability to store gas further strengthens the self-reliant attributes of the gas system, enabling it to respond to disruption or an extreme peak caused by unprecedented demand or upstream disruption. Table 2-3 summarizes these physical characteristics of gas resilience, which this section also discusses.

Table 2-3. Physical Resilience Across the Phases of Resilience

	Resilience Phases			
Characteristic	**Preparation**	**Withstanding**	**Recovery**	**Adaptation**
Underground Infrastructure	Reduces exposure to threat	Minimizes impact of potential disruptions		
Looped and Parallel T&D Network		Improves deliverability in the event of regionally isolated gas network disruption		
Self-Reliant Gas-Fired Equipment			Maintains gas delivery during an electric grid outage	
Distributed Customer Generation		Reduces electric grid demand during extreme weather event	Enables customer flexibility in the event of an electric grid disruption outage	
System Storage Capacity	Prepares system for expected demand increase	Balances supply and demand fluctuations	Improves deliverability during disruption	Facilitates supply-side diversity (renewable integration)

Source: Guidehouse

2.3.1 Underground Infrastructure

Natural gas is one of the few energy resources predominantly delivered to customers by pipeline. In contrast, other common energy forms, such as electricity, are mostly delivered by aboveground wires. Although each delivery method has advantages, the underground gas delivery system has significantly reduced exposure to disruptive events from extreme weather such as hurricanes and snowstorms. Because of this, significant weather events rarely disrupt localized segments of the network and damage is typically limited to aboveground facilities where pipeline assets may be exposed.[14]

[14] EIA. *Natural Gas Explained: Natural Gas Pipelines*. Accessed October 2020.

2.3.2 Looped and Parallel Transmission and Distribution Network

The gas system is extensively interconnected with multiple pathways for rerouting deliveries. This interconnectivity enables the sourcing of natural gas from various production centers across the country. Additionally, distribution mains are typically interconnected in multiple grid patterns with strategically located shut-off valves. These valves allow operators the ability to isolate segments of a gas system, which minimizes customer service disruptions. To reinforce the resilience of gas delivery, the valves are paired with on-system storage and mobile pipeline solutions.

> *A 2019 study by the Rhodium Group on natural gas system reliability indicated that, "the US natural gas system typically deals with a handful of disruptions every month that last a day or more. Despite these disruptions, deliverability to end-use sectors, including electric power generators, is rarely impacted because of the redundancy built into the system."[15] While this study focused on reliability, it highlights the system redundancy that is available to respond to higher-impact resilience events.*

In addition to the interconnectivity of the gas system design, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop while keeping the other in service. Further, in the event of one or more equipment failures, gas pipelines can continue to operate at pressures necessary to maintain deliveries to pipeline customers, at least outside the affected segment. Considering customer impacts of individual equipment failures in the design of gas pipelines and facilities to determine where investment in redundant infrastructure is prudent, is part of the gas utility risk management process.

2.3.3 Self-Reliant Gas-Fired Equipment

Much of the equipment used on the gas system, including compressors, dehydration equipment, pressure regulators, and heaters, are usually powered by the gas that flows through the pipes they serve. Powering equipment by the gas in the system limits the gas system's reliance on external supply chains. If gas continues to flow through the pipes—which has demonstrated to be a resilient supply chain itself—the gas system will continue to operate, and gas will flow to customers.

In some cases, the pursuit of decarbonization goals has resulted in the replacement of gas compressors with electric compressors. While electric compressors are not yet widespread, their use does reduce this resilient aspect of gas system operation.

2.3.4 Distributed Customer Generation

The US Department of Energy has documented how combined-heat and power (CHP) systems serve as a resilience solution, with specific case studies on how CHP has provided resilience for critical facilities during major weather events, giving them the flexibility to produce thermal energy and electricity onsite.[16] Example 1 highlights one such case study. CHP systems at

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[15] Rhodium Group. 2019. *Natural Gas Supply Disruption: An Unlikely Threat to Electric Reliability*.

[16] US Department of Energy. 2018. "CHP Technology Fact Sheet Series."

these facilities are largely dependent on the resilience of the US gas system and its ability to continue delivering natural gas during resilience events.

At the end of 2019, there were 3,186 commercial and industrial (C&I) CHP sites fueled by natural gas with a total capacity of 58,140 MW.[17] This distributed generation is equivalent to over 5% of total US electric power generation capacity. Distributed CHP systems exemplify how the gas system supports the resilience of end-use customers by giving them alternative options to generate heat and electricity in the case of unplanned energy system disruptions. The costs and inconvenience of a power outage can be substantial, including losses in productivity, product, revenue, and customers. Gas-fired standby generators also provide a resilience benefit by helping to avoid the impact of a power outage. This benefit is discussed further in Case Study 5.

Example 1. CHP and Distributed Generation Support Critical Infrastructure During Extreme Weather Events[18]

Hurricanes. In 2008, Hurricane Ike flooded over 1 million square feet of the University of Texas Medical Branch (UTMB) in Galveston, Texas. The hurricane interrupted utility services and resulted in the complete loss of UTMB's underground steam distribution system. Learning from this experience, the UTMB installed a 15 MW CHP facility (11 MW fueled by natural gas) to improve resilience and allow for an immediate return of hospital and clinical operations.

This resilience solution was tested during Hurricane Harvey in 2017 when the campus lost power. In circumstances that would have otherwise caused a blackout, the CHP system continued to operate during and after the storm, allowing the hospital to maintain regular operations. As a co-benefit, the CHP system saves UTMB approximately $2 million per year in utility costs and reduces campus emissions by 16,476 tons of CO_2 per year.

2.3.5 Gas System Storage Capacity

The ability to store large quantities of energy supply is a fundamental strength of the gas system allowing it to respond to, prepare for, withstand, and recover from disruption. In addition, gas storage facilities offer further geographic supply diversity to the gas system, as these storage assets can often maintain supply if disruptions are experienced on the system. Gas system storage capacity is built as a result of long-term planning in response to forecasted seasonal and peak demand. Gas system storage can be classified by where it is connected to the gas value chain.

- **On-System Storage:** This storage is operated and controlled by the LDC, allowing it to respond quickly to peak demand requirements and emergency situations. On-system storage is often aboveground, and in some situations underground. One advantage of on-system storage is that it can be sited at specific locations on the gas distribution system to best provide a resilience benefit (both supply and pressure support) in the event of an upstream disruption. This benefit is exemplified in Case Study 4.

[17] U.S. Department of Energy. 2019. *U.S. Department of Energy Combined Heat and Power Installation Database*. Accessed October 2020.

[18] Southcentral CHP Technical Assistance Partnerships. 2019. *Project Profile: University of Texas Medical Branch 15 MW CHP System*. Accessed October 2020.

- **Off-System Storage:** This storage is connected to a transmission line and is not directly tied to an LDC's distribution system. In most cases, off-system storage is underground, which makes it resilient to many climate-driven disruptions.
- **Mobile Storage:** Stored as LNG or CNG, natural gas can be moved via truck to serve short duration needs such as providing temporary supply for emergency response, pipeline maintenance, and construction and peak shaving.

The gas system's storage capacity is critical to its ability to respond to disruption. For example, the gas system storage capacity allows the gas system to respond to extreme heat and cold events when large amounts of gas are drawn in a short period. In addition, system storage provides a supply buffer allowing the LDC vital time to respond to unplanned delivery constraints in the pipeline and distribution network, resulting from gas system disruptions. The capacity of US gas storage and the associated value of that storage is further explored in Example Box 2.

Example 2. The Value of Gas Storage

In 2019, the US consumed approximately 31 trillion cubic feet of natural gas. If this natural gas was consumed in the same amount every day, the US would consume approximately 85 Bcf per day (Bcfd). But natural gas usage is seasonal – in January 2019, the US consumed nearly 110 Bcfd on average compared to approximately 71 Bcfd in June.[19]

With seasonal fluctuations in use and additional fluctuations in daily consumption, gas storage plays a vital role in balancing supply and demand. The US has nearly 400 underground storage facilities in the lower 48 states with a total storage capacity of more than 4,000 Bcf. In 2019, approximately 2,300 Bcf of natural gas supply was delivered from storage facilities, roughly the energy equivalent of 700 million megawatt-hours (MWh).[20]

NW Natural operates the Mist underground storage facility in Oregon. Its 20.1 Bcf of gas storage capacity is equivalent to 6 million MWh. Installing a battery of equivalent size on the electric system would cost approximately $2 trillion in 2020 dollars.[21]

Storage assets are additionally well positioned to support future state resilience demands and are capable of using low carbon commodities. These long-lived assets can be re-missioned to meet evolving energy system resilience requirements.

2.4 Operational Characteristics of Gas System Resilience

The industry has several operational tools at its disposal to prepare for, withstand, recover from, and adapt to disruptions. The gas system has robust management practices for the flows of gas on the system and there are several opportunities to provide flexibility in delivery and to manage demand. Table 2-4 summarizes these operational characteristics of gas resilience, which are also discussed further in this section.

[19] https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[20] https://www.eia.gov/naturalgas/ngqs/#?report=RP7&year1=2019&year2=2019&company=Name

[21] https://www.nrel.gov/docs/fy19osti/73222.pdf

Table 2-4. Operational Resilience Across the Phases of Resilience

	Resilience Phases			
Characteristic	**Preparation**	**Withstanding**	**Recovery**	**Adaptation**
Robust Management Practices	Activates backup resources, prevents and mitigates cyber threats, improves response to disruptions, facilitates learning from unanticipated disruptions			
Flexible Delivery			Improves gas deliverability during extreme conditions	
Demand-side management and energy efficiency	Reduces demand before and during extreme events		Provides gas system operators demand-side control during disruptions	
Large customer contract design		Flexibility to curtail non-firm transport customers		

Source: Guidehouse

2.4.1 Robust Management Practices

The gas industry maintains safe and resilient operations using a variety of tools including long-term resource planning, emergency response planning, standard operating procedures, and incident-response protocols. The industry also has a well-established Mutual Aid Program that allows utilities to provide and receive aid from other utility members in the event of disaster or emergency situations.[22] Pipeline operators are trained per the US Department of Transportation's pipeline safety requirements.

Gas utilities also follow robust cybersecurity protocols,[23] and align their cybersecurity programs to several key frameworks and standards including the NIST Cybersecurity Framework, the ISA/IEC 62443 Series of Standards on Industrial Automation and Control Systems (IACS) Security, ISO 27000, NIST 800-82, the TSA Pipeline Security Guidelines, and API Standard 1164.[24] Gas assets are also designed with manual override and manual backups in case of cyber disruption.

2.4.2 Flexible Delivery

In addition to on-system storage, some LDCs use mobile pipeline solutions. These non-pipeline solutions are frequently LNG or CNG tanker trucks that deliver needed supplies directly to an injection point on the distribution system in the event of a gas system disruption. The ability to deliver through multiple pathways is a valuable characteristic of the gas system.

[22] American Public Gas Association. Mutual Aid Program. Accessed November 2020.

[23] Oil and Natural Gas Sector Coordinating Council; Natural Gas Council. 2018. Defense-in-Depth: Cyber Security in the Oil and Natural Gas Industry.

[24] Natural Gas Council. 2019. Natural Gas: Reliable and Resilient.

Example 3. Operational Management Helps Prepare for and Withstand Extreme Weather Events

During the January 2019 polar vortex, a severe wave of cold weather swept over the midwestern US, bringing temperatures to well below -20°F in several states. Minnesota experienced its lowest air temperatures since 1996, reaching a low of -56°F and wind chills below -60°F in some areas.[25]

Leading up to the event, CenterPoint Energy used gas system modeling and SCADA to predict how its gas system would react to the extreme cold temperatures. Based on this data, CenterPoint Energy deployed two CNG trailers to strategic locations where additional supply might be needed and placed field crews on standby across the state. Engineering, operations, and gas control were in constant communication, as is standard practice for most cold-weather events. Though CenterPoint Energy's gas system met demand during record temperatures without the need of the CNG trailers, this example highlights how gas LDCs use robust management practices to prepare for and withstand extreme weather events.[26] CenterPoint Energy's response to the 2019 polar vortex is highlighted further in Case Study 1 in Section 3.

2.4.3 Demand Side Management and Energy Efficiency

Gas system operators have a robust toolbox to safely, effectively, and efficiently accommodate demand. Many gas utilities offer demand side management (DSM) and energy efficiency programs to support their customers in managing their gas consumption, while some are also piloting demand response (DR) programs that can include controllable devices such as connected thermostats. Implementation of these programs frequently results in resilience benefits. For example:

- Residential customers participating in weatherization programs to reduce their energy use associated with heating and cooling will enjoy a home that is more efficient and can better maintain comfortable indoor temperatures. These residents will be better able to shelter in place if they experience disruptions in their energy supply.
- Participation in energy efficiency programs in general will result in more efficient energy usage and lower annual spend on energy.
- DSM and DR programs offer grid operators the opportunity to improve the efficiency and stability of the power system by reducing the severity of demand spikes. Although these programs are often developed to increase reliability, they also offer significant resilience benefits in allowing grid operators the ability to adjust the demand side of the equation when a significant disruption is experienced.

2.4.4 Large Customer Contract Design

Gas system operators contract with large-volume customers in a way that mitigates potential physical constraints around deliverability. Large-volume customers voluntarily enter into either a firm contract (i.e., they are contractually guaranteed an agreed amount of supply, regardless of potential gas system capacity constraint issues) or an interruptible contract (i.e., their service can be interrupted if the gas system is experiencing capacity constraint issues) with the gas system. This means that gas system operators have the flexibility to contractually curtail delivery to large-volume interruptible customers in the event of disruption, a form of demand response, which is one reason why the gas system rarely experiences service disruptions.

[25] Minnesota Department of Natural Resources. 2019. *Cold Outbreak: January 27-31, 2019.* Accessed October 2020.
[26] CenterPoint Energy, Interview. October 2020.

The definitions of firm and interruptible customers may need further clarification as the gas system sees more large-volume users with dramatic swings in their maximum and minimum usage throughout a day. However, the gas system's ability to contract differently with users that use the gas system differently is a resilience characteristic that must be recognized.

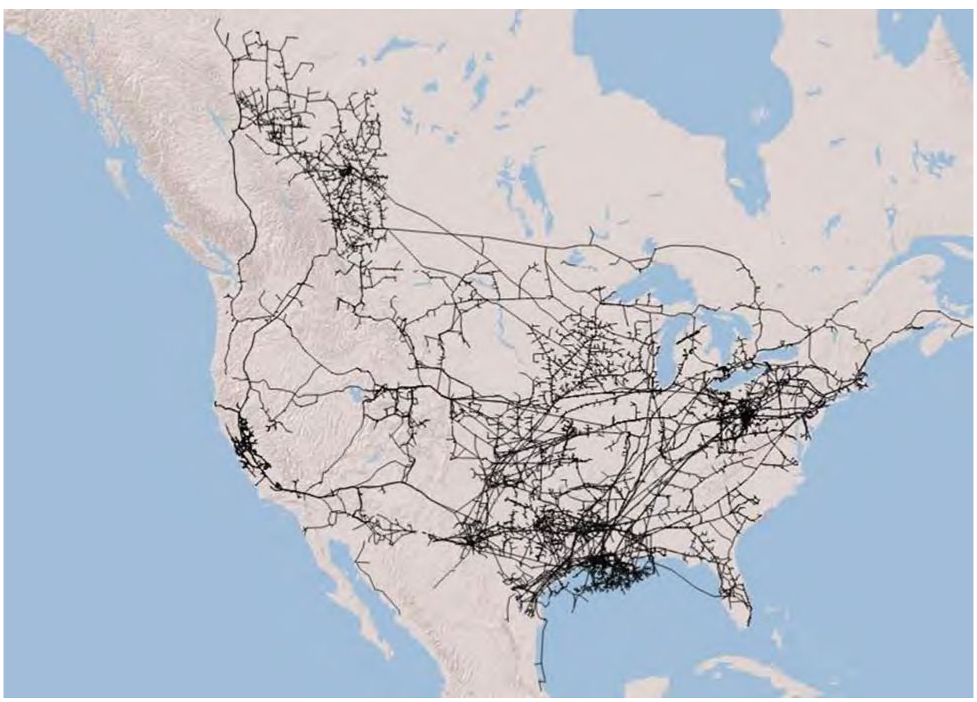
2.5 Resilience Limitations

The overall US gas system's network contributes to its stability but the degree of interconnectedness on the network can vary across LDCs based on the following two primary factors:

- The availability of operational capacity on upstream pipelines and storage
- The physical location of the LDC service territory in relation to pipelines and storage facilities

As Figure 2-4 illustrates, some US regions have more access to the transmission system than others. For example, the Pacific Northwest is supplied by fewer pipelines compared to the Upper Midwest and the Gulf Coast. A gas utility or geographic region with limited access to multiple transmission pipelines will need to leverage other resilience solutions to develop transportation and supply diversity, such as storage.

Figure 2-4. Major North American Natural Gas Pipelines



Source: S&P Global Market Intelligence

3. Proving It: Resilience in Action

The inherent, physical, and operational capabilities of the gas system—from receipt of supply from the upstream pipelines to the ability to provide short-notice storage withdrawal and injection rates—enable it to meet the volatile demand profiles resulting from resilience events. This section includes six case studies that exemplify how the gas system contributes to the resilience of the US energy system.

It is a testimony to the preparedness and true resilience of the industry that there are so few case studies of extra measures ever needing to be taken to respond to periods of extraordinarily high demand.

Polar Vortex (January 2019)

- In Case Study 1, the use of a diverse mix of gas resilience assets (upstream pipelines, storage, LNG and propane storage, flexible non-pipeline assets) allowed the gas system to meet record peak demand resulting from extreme cold temperatures.
- In Case Study 2, the integral role the gas system plays in supporting the space heating needs of customers in colder climates is explored. The case study also demonstrates that during a peak event, the gas system currently delivers substantially more energy than the electric system is built to deliver.
- In Case Study 3, the resilience attributes of the gas system were put to the test when a fire caused a failure on a critical gas compression and storage facility. Despite losing almost one-third of its on-system storage, the gas utility withstood this failure during a period of peak demand without involuntary loss to a single residential customer.

Polar Vortex (February 2014)

- In Case Study 4, the role of natural gas storage, both underground and aboveground, as a critical resilience solution to meet record gas demand is demonstrated.

Hurricane Isaias (August 2020)

- In Case Study 5, natural gas was used as a backup power source to ensure essential power functions could continue to be met for residential and commercial customers in the middle of a hurricane.

Heat, Drought, and Wildfires (August 2020)

- Case Study 6, storage capacity resources were used to meet the supply needs of gas-fired generation plants when the California electric system experienced high demand from a record-breaking heatwave and unplanned reductions in other sources of generation.

Case Study 1: Meeting Record Peak Demand (Minnesota)

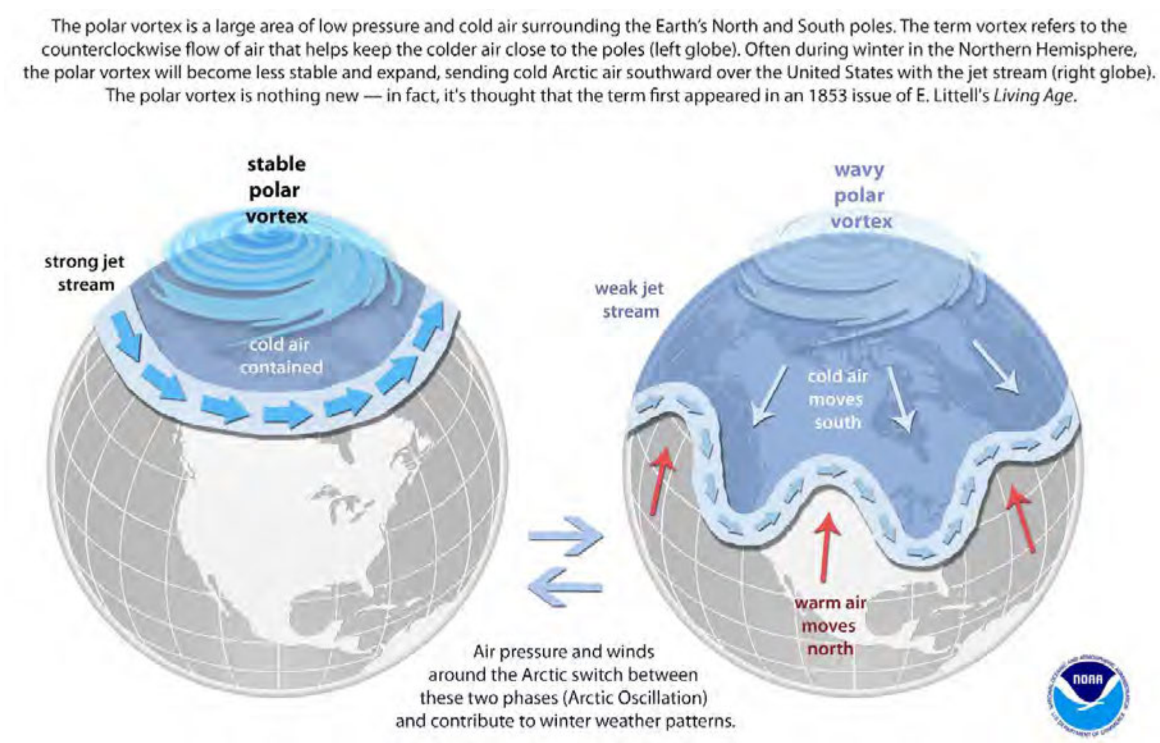
Key Finding

CenterPoint Energy used a diverse mix of gas resilience assets (upstream pipelines, storage, LNG and propane storage, flexible non-pipeline assets) to meet record peak demand resulting from extreme cold temperatures across the Midwest.

Introduction

The first three case studies pertain to the January 2019 Polar Vortex, when a weakened jet stream resulted in the coldest temperatures in over 20 years to most affected regions across the US and Canada (Figure 3-1). The event resulted in at least 22 deaths and grounded around 2,700 flights across the Midwest and Northeast.

Figure 3-1. The Science Behind the Polar Vortex



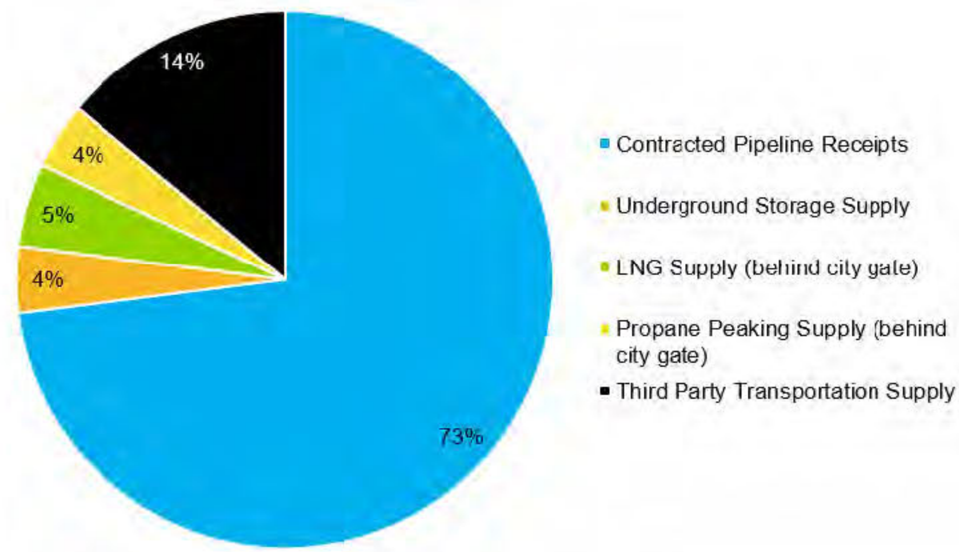
Source: National Oceanic and Atmospheric Administration

Overview

During the January 2019 Polar Vortex, in Minneapolis, Minnesota, the average temperature was -19°F from January 29 to 30. The coldest hour occurred at 6:00 a.m. on January 30 when the temperature was -30°F (before wind chill). On these days, CenterPoint Energy (which serves 870,000 customers in the greater Minneapolis region) experienced record daily delivery of natural gas of 1,495,000 Dth on January 29 and 1,448,000 Dth on January 30. This compares to 1,000,000 Dth of daily sendout in a typical January day, or a 49% and 44.8% increase over average for January 29 and 30, respectively.

Because the demand for gas was so high on CenterPoint's gas system on January 29 and 30, interruptible customers and interruptible transportation service deliveries were curtailed to maintain distribution system integrity for firm demand customers. Even after curtailing these customers, CenterPoint Energy needed to pull gas supply from every available source, as Figure 3-2 illustrates. Approximately 13% of the gas delivered to CenterPoint's customers in Minneapolis on these very cold days was supplied by storage, including LNG and propane assets, which played a critical role in providing additional supply and pressure to maintain gas system integrity.

Figure 3-2. Gas Supply by Source, CenterPoint Energy, Minneapolis, Minnesota, January 29-30, 2020



Source: Guidehouse, CenterPoint Energy

Like many gas utilities, this planning consists of a thorough review of gas supply plans and monitoring of distribution system performance in addition to heightened staffing to be prepared for quick response to issues.

Table 3-1. CenterPoint Energy Actions to Maintain Gas System Viability During the 2019 Polar Vortex

Phase of Resilience	CenterPoint Actions to Maintain Gas System Deliveries in Response to the 2019 Polar Vortex
1. Preparation	• Daily review of supply plans by gas supply, gas control, peak shaving, and engineering. • Daily preparation and execution of cold weather engineering plans. • Daily staging of operations technicians in critical locations to monitor/react. • Daily staffing of engineering personnel in the cold weather ops center to support system operations and gas control. • Dispatch Center: Extra staff added to coordinate with field operations. • Field operations: Implementation of cold-weather operating plans.

Phase of Resilience	CenterPoint Actions to Maintain Gas System Deliveries in Response to the 2019 Polar Vortex
	• The areas requiring CNG trailer deployment were identified using system modeling and SCADA to help predict how the system would react during the cold event. • Two CNG trailers were deployed and on standby. These flexible non-pipeline solutions provided just in time delivery to reinforce system operations
2. Withstanding	• Aside from the CNG locations, CenterPoint Energy positioned several field crews at different locations throughout its service territory on standby to be responsive should an unexpected issue arise. In addition, critical groups, including engineering, operations, and gas control were in constant communication to monitor the system.
3. Recovery	• The system did not incur any damage or major disruptions, so there was no recovery phase for this event.
4. Adaptation	• System reinforcements were identified and later completed for the areas where CNG trailer were deployed. • Regular review of distribution system performance as cold weather occurs. • Adjustments are made if needed and as possible. • Testing and operation of stations and equipment.

Source: Guidehouse, CenterPoint Energy

Conclusion

CenterPoint Energy's use of a diverse mix of gas system resilience assets to meet record peak demand from a climate event exemplifies how the gas system contributes to the energy system's overall stability. Upstream pipelines, storage, LNG and propane storage, and flexible non-pipeline assets were deployed for addressing unplanned or unforeseen events within the integrated energy system.

Case Study 2: The Role of Natural Gas (Illinois)

Key Finding

During the 2019 Polar Vortex, Nicor Gas, Peoples Gas, and North Shores Gas' daily distributions of natural gas (7.32 Bcf) were equivalent to 90GW of electricity—more than 3.5 times the amount of electricity that ComEd, the electric utility serving a similar territory has delivered in a single day. The gas system provides value in the volume of energy that can be delivered during peak events, which will require significant infrastructure buildout to be replaced.

Introduction

During the record-breaking cold weather that occurred January 30 and 31, 2019, Nicor Gas, the LDC serving 2.2 million customers in Illinois delivered more than 4.88 Bcf of natural gas per day. This is more than double the natural gas delivered on a typical day in January day. In terms of energy delivery, this amount of gas, an average of 0.20 Bcf per hour, compares to approximately 61 GW of electricity.[27] This is the single largest delivery of natural gas in the company's history—surpassing previous records set when 4.5 Bcf was delivered between January 6 and 7, 2014.

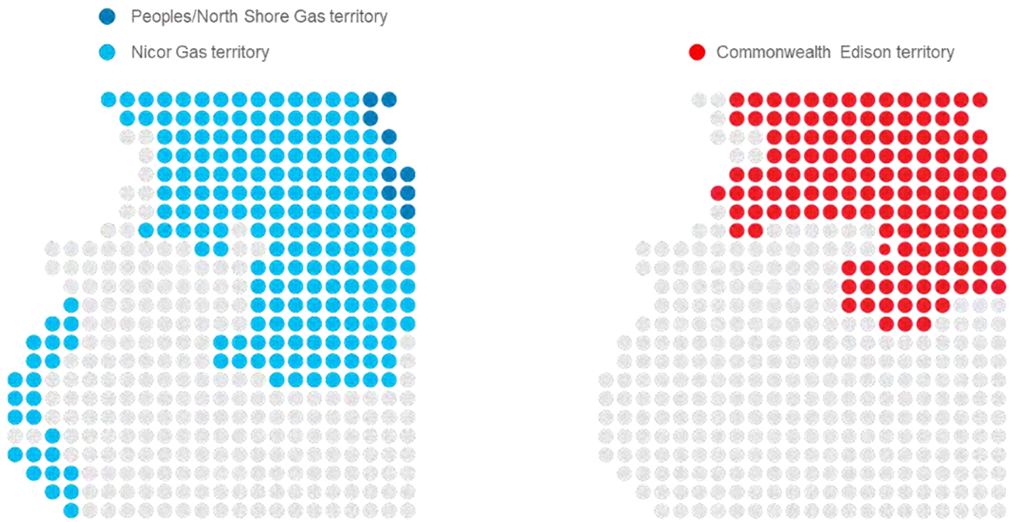
Nicor Gas employees worked around-the-clock during this cold weather to monitor the distribution system to ensure the safe performance and reliability of the infrastructure. More than 7,000 customer calls were received at the customer contact center and field operations responded to nearly 1,500 emergency calls for service during the two days. There were no major service outages during the weather event.

Overview

On January 30, 2019, together Peoples Gas, North Shore Gas, and Nicor Gas distributed more than 7.32 Bcf of natural gas—this is comparable to approximately 90 GW of electricity and represents more than 3.5 times the amount of electricity that ComEd, the electric utility serving northern Illinois, has ever delivered in single day (Figure 3-3). Even on a typical day, the Nicor Gas system alone delivers an amount of energy that is approximately equal to the maximum amount of energy that ComEd has ever delivered on a single day. The historic peak delivery day for the ComEd system is 24.8 GW, which occurred on July 20, 2011.

[27] Calculation: 4.88bcf/24 hours*10^9 scf* 1,020 Btu/scf * 1 kWh/3,412 Btu = 60, 785, 463 kW (or 60.8 GW)

Figure 3-3. Energy Distribution by Northern Illinois Utility



Utility	Peak demand (gas)	Peak demand (electricity)
Peoples Gas/North Shore Gas	~2.44 Bcf	~30.4 GW*
Nicor Gas	4.88 Bcf	~60.8 GW*
ComEd Historic Peak Demand on July 20,2011		24.8 GW

Source: Nicor Gas Company

There are several takeaways for regulators and policymakers that emerge from this case study. First off, it is critical to understand the implications of electrification on infrastructure investment, not just for a typical day, but for a peak event.

The gas system plays an integral role in supporting the space heating needs of customers in colder climates. Moreover, in the wintertime, space heating requirements typically begin to increase in the early morning and late afternoon hours; these are times when intermittent, renewable resources may not be available. Without the gas system, battery storage with significant duration and capacity capabilities would be required to bridge the gap between generation from intermittent, renewable resources and heating demands.

The gas system provides value in the volume of energy that can be delivered during peak events, which will require significant infrastructure buildout to be replaced.

Case Study 3: Ray Compressor Station Fire (Michigan)

Key Finding

Despite the loss of availability of the largest storage facility on its gas system, Consumers Energy was able to serve all of its customers without any involuntary disruption during a period of record cold temperature and peak demand.

Introduction

As the CenterPoint Energy and Nicor Gas case studies demonstrate, the Polar Vortex of January 2019 placed enormous stress on the gas delivery system under record-setting conditions. When extreme cold weather hit Michigan from January 29 to February 1, Consumers Energy was prepared to fulfill demand utilizing gas storage and pipeline supply as the primary supply sources. Consumers Energy had 61.9 Bcf of working natural gas inventory, above its target of 61.4 Bcf during a typical winter.

Gas storage fields play a critical role in enabling Consumers Energy to serve its customers during times of peak demand. They are used to meet demand at various levels:

- **Baseload demand:** Along with pipeline supply, baseload storage fields run daily during the winter to meet a foundation level of demand.
- **Intermediate demand:** Intermediate storage fields run during longer periods of higher demand.
- **Peak demand:** Peaker (and needle peaker) storage fields run during the extreme hours and days when demand changes quickly, typically in the early morning when customers start their day and their gas appliances.

Consumers Energy operates 15 storage fields with a total working capacity of 149 Bcf. The largest, the Ray Peaker field, has a capacity of 47.52 Bcf, or almost one-third of Consumers Energy's working storage capacity. The Ray facility is a combination compressor station and adjacent storage field.

Consumers Energy planned to fulfill demand during this cold period using baseload production storage fields, Ray field, and pipeline supply as the primary sources. Its other peaker fields were in reserve to support gas system packing and address any potential interruptions in pipeline supply, baseload fields, and compressor stations.

Incident

At approximately 10:30 a.m. on January 30, a fire occurred at the Ray Natural Gas Compressor Station. The fire reduced the amount of natural gas Consumers Energy could deliver to customers from underground storage in the Ray field near the compressor station. The damage to its largest storage and delivery system, which occurred during historically high natural gas demand due to cold temperatures, prompted Consumers Energy to take steps to ensure gas deliveries to its customers continued uninterrupted.

Response

Consumers used a variety of inherent, physical, and operational resilience characteristics to respond to the supply disruption during historic cold temperatures. Throughout the entire event, not a single critical, priority, or residential customer lost service involuntarily.

Table 3-2. Summary of Resilience Characteristics Used by Consumers Energy

Date	Key Resilience Characteristics
2018	• Consumers Energy held a training exercise in 2018 with a scenario involving a fire at Ray Compressor Station. This prepared employees by providing an opportunity to **rehearse emergency response** roles and responsibilities.
January 24, 2019	• In preparation of forecasted extreme cold temperatures, notice was given to **interruptible customers** that interruptible service would not be available beginning January 25.
January 30, 2019	• System **linepack** provides immediate buffer to sudden loss of storage supply from approximately 10:30 a.m. to 8:00 p.m. • At 10:45 a.m., Consumers Energy leveraged its **networked system** by calling five major interconnected pipelines that agreed to provide supply on a best effort basis. • **Peaker storage fields** were dispatched and began flowing at approximately 11 a.m., reducing sole reliance on linepack. • At 1 p.m., Consumers Energy began requests for **voluntary load reductions** from 104 of its highest volume customers. • Procurement of additional supply. • Formal **curtailment** for large transport customers began at approximately 3 p.m. • At 8 p.m., Consumers Energy worked with the governor to use the **Emergency Broadcast system** to ask residential customers for voluntary natural gas reductions. • Near 11 p.m., some of the Ray facilities supply capabilities were returned to service.
January 31, 2019	• Continued curtailment enables additional 40,000 Mcf of demand reduction.
February 1, 2019	• Announcement of cessation of curtailment at 8:22 a.m.

Source: Guidehouse, Consumers Energy

As Figure 3-4 shows, the loss of gas supply from the Ray facility caused the gas system to begin unpacking at an excessive rate. Unpacking means the amount of gas and the available pressure in the pipeline are decreasing and it occurs when the rate of total supply is lower than the rate of total delivery to customers. Figure 3-4 depicts the status of supply, demand, rate of gas system unpack,[28] and Ray Field flow on January 7, prior to the event. It also shows several points including the peak hour of January 30 at 11:00 p.m. and the peak hour of the next day at

[28] Unpack refers to the system's use of linepack.

8:06 a.m. on January 31. The loss of Ray and the rate at which the pipeline system was unpacking caused key gas system pressures to decline at excessive rates.

Shortly after the fire-gate alarm was received, Consumers Energy Gas Control adjusted the storage field rate orders to dispatch all peaking storage fields at maximum flow rates including those fields on standby. The peaking storage fields added approximately 975 MMcf/day of supply. The dispatch of the peaking fields maximized the total amount of storage supply delivered and reduced the gas system unpack rate. In addition, additional supplies provided by neighboring pipelines helped to mitigate the loss of supply from the Ray storage field (shown in light green in Figure 3-4 and the corresponding reduction in gas system unpack is shown in light green cross-hatching).

Figure 3-4. Consumers Energy System Supply, Demand, and Reserve Capacity January 30-31, 2019

Source: Guidehouse, Consumers Energy

Consumers Energy took several steps to mitigate the impact of the loss of access to the Ray storage field. These steps included requests for voluntary reductions in gas usage of all customers. Consumers Energy also implemented an Operational Flow Order (OFO) for the first time in its history for natural gas transportation customers, which required those customers to match their natural gas deliveries to Consumers Energy's system to their usages. When the requests for voluntary actions and the OFO did not result in the reductions in gas usage necessary to stabilize the gas system, Consumers Energy implemented a mandatory curtailment of gas deliveries to large business customers for the first time in its history, which required a reduction in their natural gas usage down to minimum loads required to protect equipment. In cooperation with Governor Whitmer, Consumers Energy also requested all-natural gas customers in Michigan to conserve natural gas by dialing down their thermostats. On Thursday, January 31, Consumers Energy announced that the appeal for assistance would end at 12:00 a.m. on February 1 for all customers—commercial, industrial, and residential.

Conclusion

This Ray Compressor fire event and the subsequent recovery by Consumers Energy is a unique story of the resilience characteristics of the gas system. Despite the loss of availability of the largest storage facility, not a single critical, priority, or residential customer lost service involuntarily during a peak of record cold temperature throughout the region, due to the fire-gate event.

Consumers Energy was able to withstand, recover, and adapt due to diligent advanced preparation and execution of its emergency response plan during the event. Access to physical assets is a key contributor to resilience. The ability to use alternate flow paths within facilities enables the recovery of the gas system and the return to customer's ability to use gas normally. Consumers Energy's ability to use existing storage assets as a first response demonstrates this opportunity. However, practice, preparation, and planning are also critical contributors to resilience, as demonstrated by Consumers Energy's response.

The company's capabilities in emergency management, including the use of an Incident Command System (ICS), enabled it to respond rapidly and organize into an ICS structure that included both a command post and an Emergency Operations Center (EOC). The well-defined chain of command, incident objectives, and tactics allowed for effective internal coordination of resources. It also enabled fast, complete, and transparent engagement with the MPSC, State Emergency Operations Center (SEOC), and the Governor's office throughout the event. Furthermore, it provided an organized approach to protect life and safety, to stabilize the incident, and to protect property and the environment.

Case Study 4: The Role of Winter Gas Storage (Oregon)

Key Finding

Storage assets, in combination with diligent planning and dedicated employees, play a critical role in providing natural gas during periods of critical demand in response to cold weather events.

Introduction

Northwest Natural (NW Natural) provides service to approximately 2.5 million people in Oregon and southwest Washington state (Figure 3-5). The Portland metro area represents the largest portion of NW Natural's customer demand, and its weather is characterized by a temperate oceanic climate with warm, dry summers and mildly cold, wet winters.

Figure 3-5. NW Natural Service Territory

Source: NW Natural

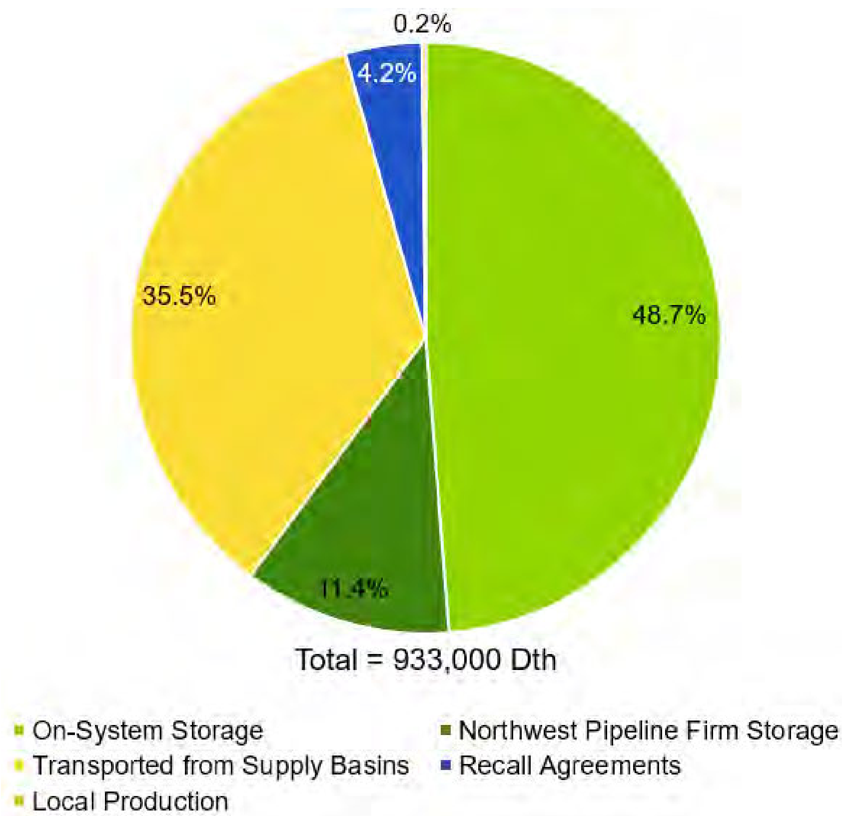
NW Natural personnel oversee the safe operation of 14,000 miles of transmission and distribution mains, monitor deliveries at over 40 interconnections with the upstream interstate pipeline system, and coordinate the usage of three on-system storage facilities (one underground storage and two LNG plants) along with off-system storage. The Gas Control department, as an example, is responsible for forecasting near-term loads, monitoring pressures, flows and other conditions using telemetry data fed from field devices, electronically controlling certain field equipment, and determining the usage rates of the on-system storage facilities, all on a 24/7 basis.

NW Natural's resource planning is designed to meet customer needs during an extreme cold weather event, occurring in late January or early February. One such event occurred in February 2014.

The Winter of 2013-2014

Extreme cold weather in early December 2013 set the stage for a challenging winter. Storage facilities are usually full at the start of the heating season, and large quantities can be withdrawn to meet sudden surges in sales. Stored gas is akin to a large battery, representing energy reserves that can be held indefinitely while remaining ready at short notice to satisfy customer requirements. On extremely cold days, stored gas is expected to supply approximately 60% of NW Natural's firm sales load (Figure 3-6). On February 6, 2014, total sendout set a record of 900,000 Dth that still stands today. NW Natural's prior record was 890,000 Dth, set on January 5, 2004. Stored gas played a critical role in meeting this record demand and provided nearly 50% of total sendout on this day.

Figure 3-6. NW Natural Peak Day Firm Resources, as of Nov 1, 2013



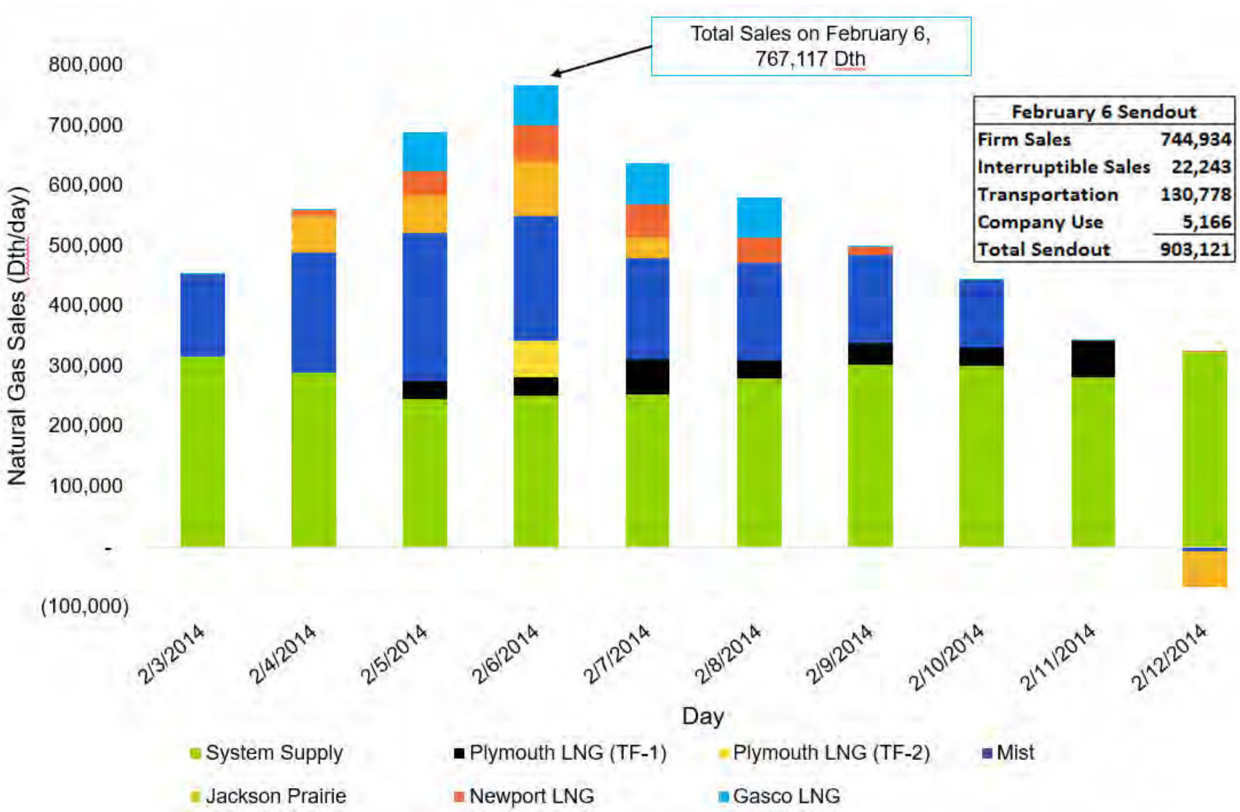
Source: Guidehouse, NW Natural

Stored gas, once withdrawn, will likely not be replenished until the following summer. Also, deliverability from storage can decrease as volumes are withdrawn, so the decision was made in December to procure additional supplies in the market in order to conserve the usage of storage gas. This planning proved extremely valuable later in the season.

The Peak Event

During early February, cold temperatures were accompanied by about a foot of snow and freezing rain. While this winter storm episode was not quite as long and cold as that experienced in the December event, a very high wind chill factor increased customer demand by an estimated 10 percent over what would be normal based on cold temperatures alone. During this period, storage resources were relied on heavily for both economic and delivery resilience reasons, growing to over 50% of daily sales requirements and then subsiding within a week's time (storage resources are all non-green colors in Figure 3-7).

Figure 3-7. NW Natural Resource Utilization During Cold Weather Event, February 3-12, 2014



Source: Guidehouse, NW Natural

Similar to the December event, in February, NW Natural had employees monitoring and controlling gas pressures at specific locations in North and East Vancouver (Washington), Southwest Salem, and South Eugene. The company also rotated two CNG trailers to support the morning peak demand in an isolated area of Northwest Vancouver, Washington.

Employee dedication and resourcefulness during the peak event included field crews manually controlling pressure regulators to ensure the maximum amount of gas could move through the pipes, storage operators working around the clock to maximize gas availability, Gas Control working with the upstream interstate pipeline to increase gate station throughput, and service technicians responding to four times the normal volume of customer calls.

Snow and ice took their toll on the gas system, requiring exceptional emergency response. For example, trees burdened by snow fell onto buildings and gas meters, some members of the public lost control of their vehicles and ran into gas meters, and parts of buildings collapsed onto gas meters. Some employees had to carry chainsaws in order to remove fallen trees blocking their way.

Aftermath

Several parts of NW Natural's service territory had seen significant customer growth over the prior two decades, and experience gained during the 2013-14 winter confirmed the need to reinforce the supply system to these areas. Besides reports of a handful of isolated customer outages, the only significant distribution system problem was in Clark County, Washington, where service had to be curtailed to four industrial interruptible customers during the morning burn hours.

Curtailment of service to interruptible sales and interruptible transportation customers is an explicit feature of NW Natural's resource planning. During the winter of 2013-14, interruptible customer curtailments were minimal because supplies were abundant, capacity was relatively unconstrained, and the gas system showed its resilience during weather conditions that tested but did not reach the extremes of the company's resource planning standards.

Case Study 5: Hurricane Response (New Jersey)

Key Finding

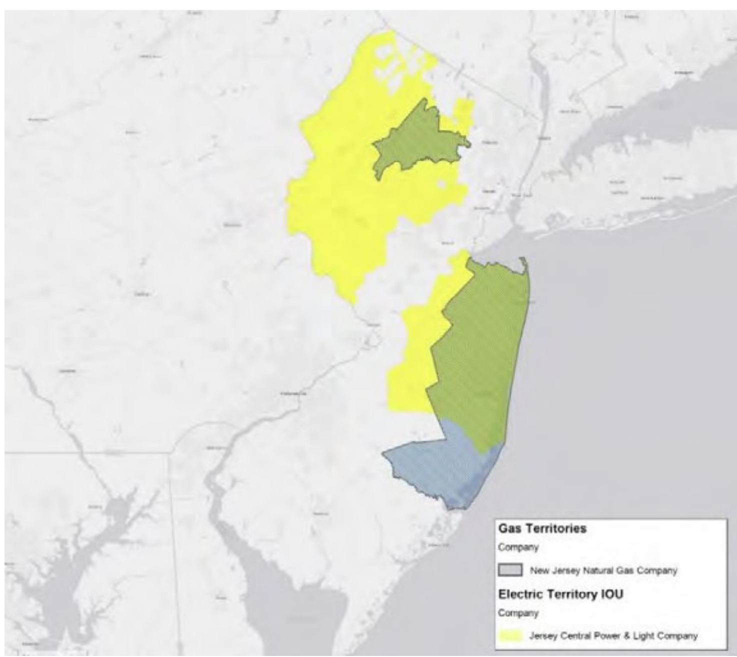
New Jersey Natural Gas Company delivered significantly more gas than normal in a short period to support backup electric power generation for residential and commercial customers in the middle of a hurricane.

Introduction

Hurricane Isaias was a destructive Category 1 hurricane that caused extensive damage across the Caribbean and the US East Coast. The hurricane made landfall near Ocean Isle Beach, North Carolina on August 4, 2020. Shortly after landfall, it was downgraded to a tropical storm.[29] When the storm reached the New Jersey region, it caused extensive damage and caused power outages that affected more than 1 million New Jersey homes and businesses.

Of the +1 million homes and businesses that lost power during Hurricane Isais, 788,000 were customers of Jersey Central Power & Light. As these customers saw an outage in their electric service, many turned to their natural gas generators to meet their power needs. New Jersey Natural Gas (NJNG), the gas provider for much of Jersey Central Power & Light's territory (Figure 3-8), experienced a massive increase in gas demand as these gas generators turned on.

Figure 3-8. Service Territories for Jersey Central Power & Light Company and New Jersey Natural Gas Company



Source: S&P Global Market Intelligence

[29] Len Melisurgo. August 8, 2020. "As bad as Tropical Storm Isaias was, here's why experts say N.J. dodged a bullet." *NJ.com*.

Overview

On Monday, August 3, the day before Hurricane Isaias caused the power outages, NJNG supplied 54,000 Dth to customers. On Tuesday, in response to the significant electric outages, NJNG supplied 84,536 Dth to customers, an almost 60% growth in daily demand in 24 hours. By the end of the week after most of the power was restored, the daily gas supplied by NJNG had dropped back to 58,394 Dth, in line with pre-storm sendout. Table 3-3 details the natural gas supplied by NJNG between August 3 and August 9, 2020.

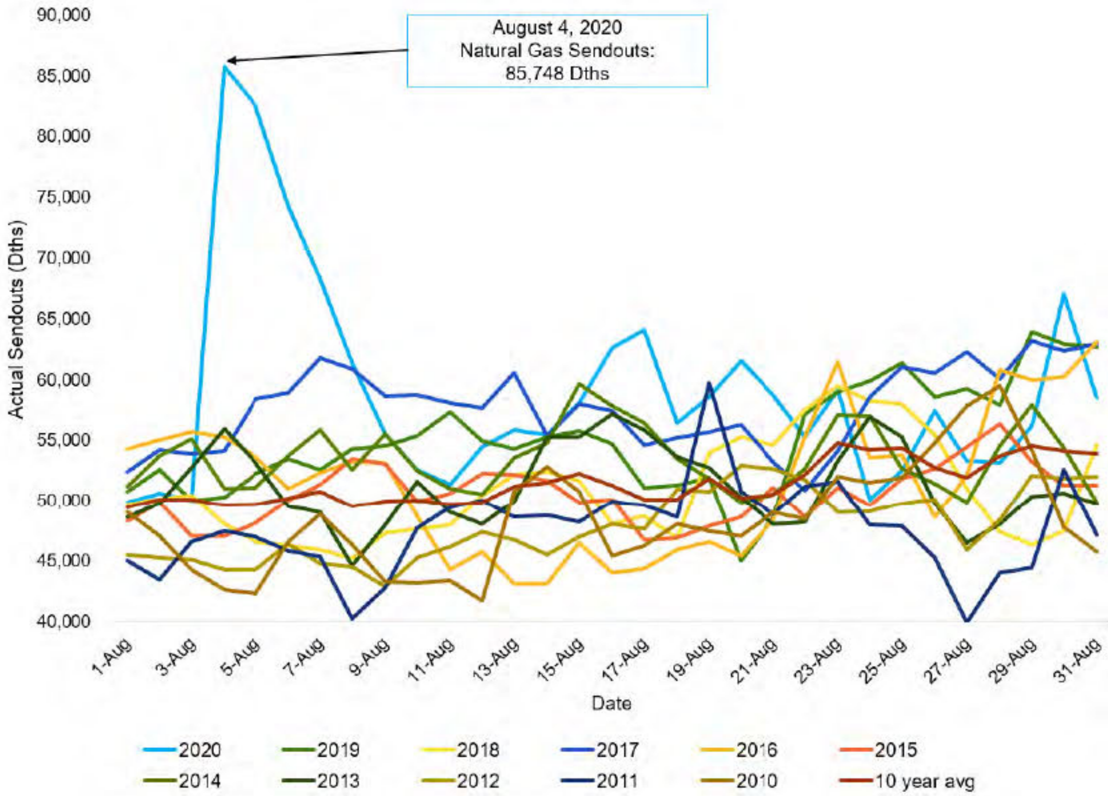
Table 3-3. NJNG Load Sendout: August 3, 2020 through August 9, 2020

Day	Date	Base Load Sendout (Dth)	Notes
Monday	8/3/2020	54,000	Pre-Storm Baseline
Tuesday	8/4/2020	85,536	Storm Hit 788,000 JCPL customers impacted
Wednesday	8/5/2020	84,198	Widespread Power Outages
Thursday	8/6/2020	78,688	Widespread Power Outages
Friday	8/7/2020	71,497	Widespread Power Outages
Saturday	8/8/2020	62,945	Majority of Power Restored
Sunday	8/9/2020	58,394	Majority of Power Restored

Source: Guidehouse, New Jersey Natural Gas

The daily natural gas output supplied by NJNG from August 4 through August 7, 2020 was higher than the daily output of any other August day for the previous 10 years. Figure 3-9 shows the 10-year average sendout from NJNG, the sendout from NJNG for the month of August 2020 identifying the dramatic peak from August 4 through 7, and the actual sendout from NJNG for August 2010-2019.

Figure 3-9. NJNG Comparison of August Actual Sendouts (Firm)



Source: Guidehouse, New Jersey Natural Gas

NJNG accredits most of the 30,000 Dth to 35,000 Dth increase in natural gas sendout during the storm to powering whole house generators, which served as backup power for customers who lost their electric supply. This load increase is estimated by NJNG to correlate with approximately 4,200, 20 kW generators running at full load (calculated using the assumptions in Table 3-4), or likely a larger number of natural gas generators running at partial load.

Table 3-4. Home Natural Gas Generator Assumptions

Generator Size (kW)	therms/ hour	dth/ hour	dth/ day	At 30,000dth/day number of 20 kW generators
20	3.00	0.30	7.20	Approximately 4,200

Source: Guidehouse, New Jersey Natural Gas

Conclusion

In August 2020, NJNG was not only able to withstand the hurricane, but it was also able to ramp up natural gas sendout quickly by relying on storage, allowing thousands of homes and businesses across New Jersey to keep their gas systems in operation when electric service was disrupted. Because of the built-in flexibility and dispatchable nature of the gas system, the gas system can complement the broader energy system as it responds to extreme climate events and keeps power flowing.

Case Study 6: Gas-to-Power Interface (California)

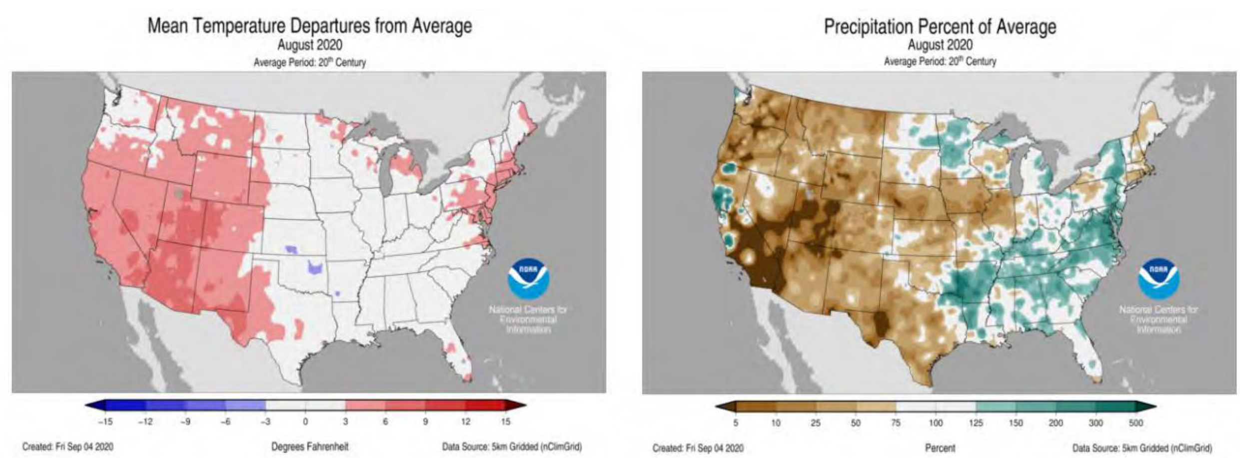
Key Finding

SoCalGas used storage capacity resources to meet the supply needs of gas-fired generation plants when the California electric system was experiencing multiple days of high demand from a record-breaking heatwave and unplanned decreases in other sources of electric generation.

Introduction

In August 2020, California was in the middle of its hottest August (record warmest in 126 years),[30] a severe drought (Figure 3-10), and its worst wildfire season in modern history. While California experienced increased demand on the electric system driven by increased cooling loads, it also experienced a decrease in the renewable output (due to smoke from the fires)[31] and imports than had been anticipated by electric supply planners. During these severe multi-day climate events, the gas system provided the flexible support required to ensure the broader energy system could provide power and prevented more extensive power outages.

Figure 3-10. August 2020 Mean Temperature and Precipitation, Departure from Average



Source: National Oceanic and Atmospheric Administration

On a standard summer day, California's electric grid is supplied by a wide variety of electric generation, renewables, natural gas, hydro, nuclear, coal, and imports from other regions. July 12, 2020 exemplifies a standard summer day in California (while the state was starting to experience a severe drought in July, average temperatures were within the normal range).[32]

[30] NOAA. National Climate Report – August 2020. https://www.ncdc.noaa.gov/sotc/national/202008

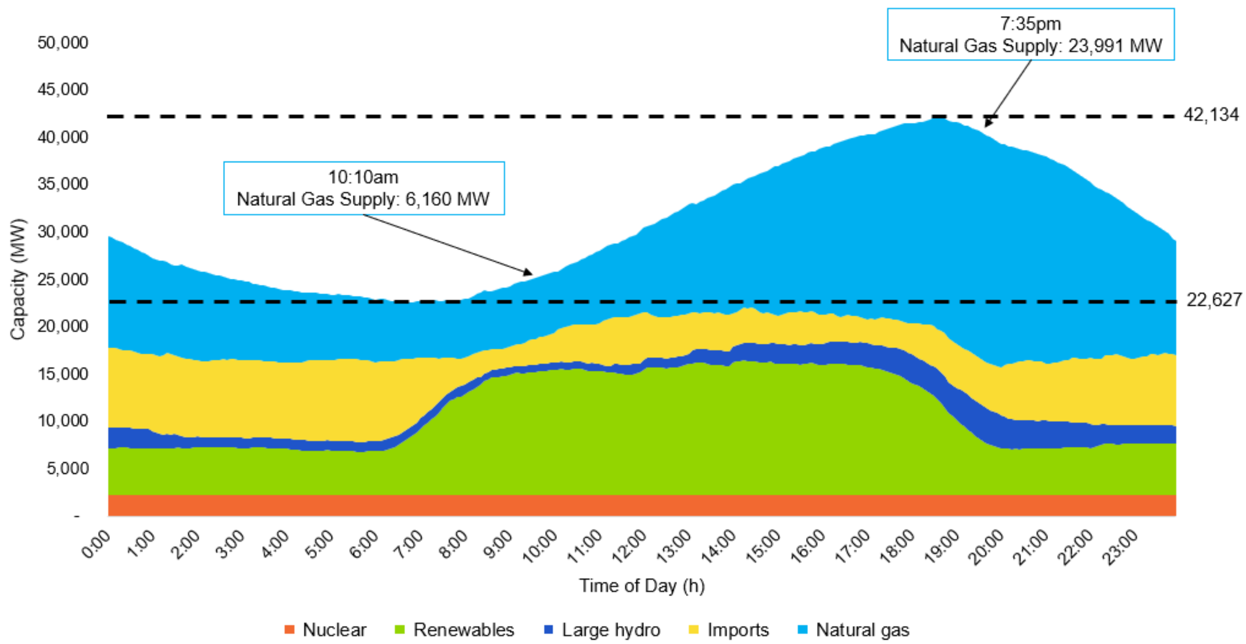
[31] EIA. *Smoke from California Wildfires Decreases Solar Generation in CAISO.* September 30, 2020. https://www.eia.gov/todayinenergy/detail.php?id=45336

[32] NOAA. National Climate Report – July 2020. https://www.ncdc.noaa.gov/sotc/national/202007

Overview

As Figure 3-11 shows, on July 12, 2020 renewable generation began to increase at around 06:30 hrs and remained relatively steady until approximately 17:00 hrs, driven primarily by solar generation during sunlit hours. By 08:00 hrs renewables provide 50% of the state's electric power generation, natural gas provides 25%, and the other sources provide the remaining 25%. As the day continues, gas-fired generation ramps up. By 20:00 hrs natural gas provides 60% of the electric power generation required to meet the peak load.

Figure 3-11. CAISO Supply Trend to Meet Electric Demand, July 12, 2020[33]



Source: Guidehouse, California Independent System Operator

Gas generation plants ramp up to meet peak demand, but the fuel demand of the generation plants is not ratable. Ratable is generally described as levelized demand where deliveries are made evenly throughout a delivery day. The hourly demand for gas to supply these generation plants often exceeds supply receipts, as arranged by the power plants, into the gas system. To overcome the imbalance between supply and use and to respond to the volatile demand needed to maintain the integrity of the electric system, underground storage plays a vital role.

Storage capacity and the stored commodity are contracted for in advance. Underground gas storage is expected to be used to maintain grid load balance and operation on high heat summer days (a hallmark of grid resilience). However, reliance on gas storage systems and the dispatchable nature of gas generation when the energy system is under higher stress (experiencing a resilience event), as seen in August 2020, requires a more significant drawdown of underground storage assets.

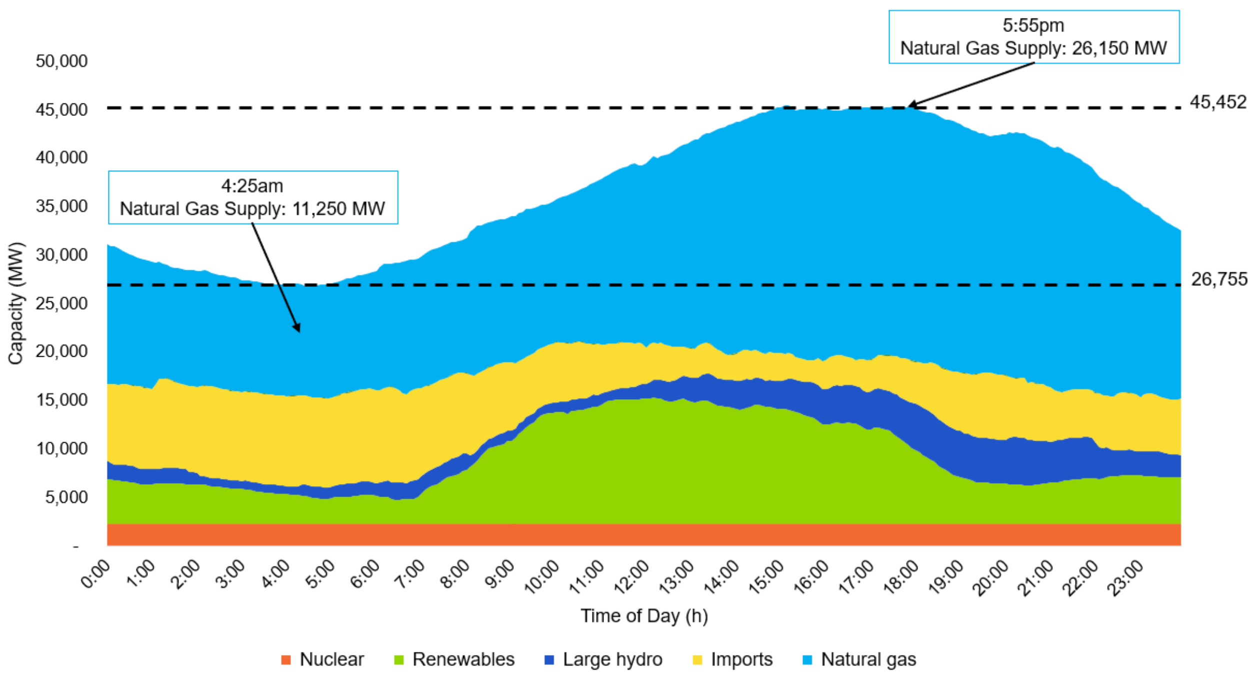
> *During the hours of highest electricity demand, gas generation provides the bulk of California's electric power generation.[34]*

[33] Batteries and coal contribute negligible amounts (± 50 MW) and are not shown within the figure.
[34] CAISO. 2020. "Supply and renewables."

The week of August 11, 2020 is a prime example of the California electric grid under a resilience event—coinciding extreme heat, drought, and wildfires. During this week, California experienced severe climatic events and associated higher electric consumption. Renewable output was also more variable and diminished due to heat, clouds, and wildfires, and power imports were lower than expected, since the entire western half of the US was experiencing the same heatwave as California.

Figure 3-12 illustrates the resources that contributed to CAISO's electric generation on August 17, 2020. Renewable generation supplied less electricity on August 17 compared to July 12 (peaking at around 13,000 MW at 12:00 hrs compared to over 14,000 MW at 14:00 hrs). Peak load was 45,452 MW on August 17, while on July 12 peak load was 42,134 MW. To meet the higher peak load and make up for the lower renewable generation, on August 17, gas-fired generation made up a higher percentage of CAISO's electric power generation capacity.

Figure 3-12. CAISO Supply Trend to Meet Electric Demand, August 17, 2020[35]



Source: Guidehouse, California Independent System Operator

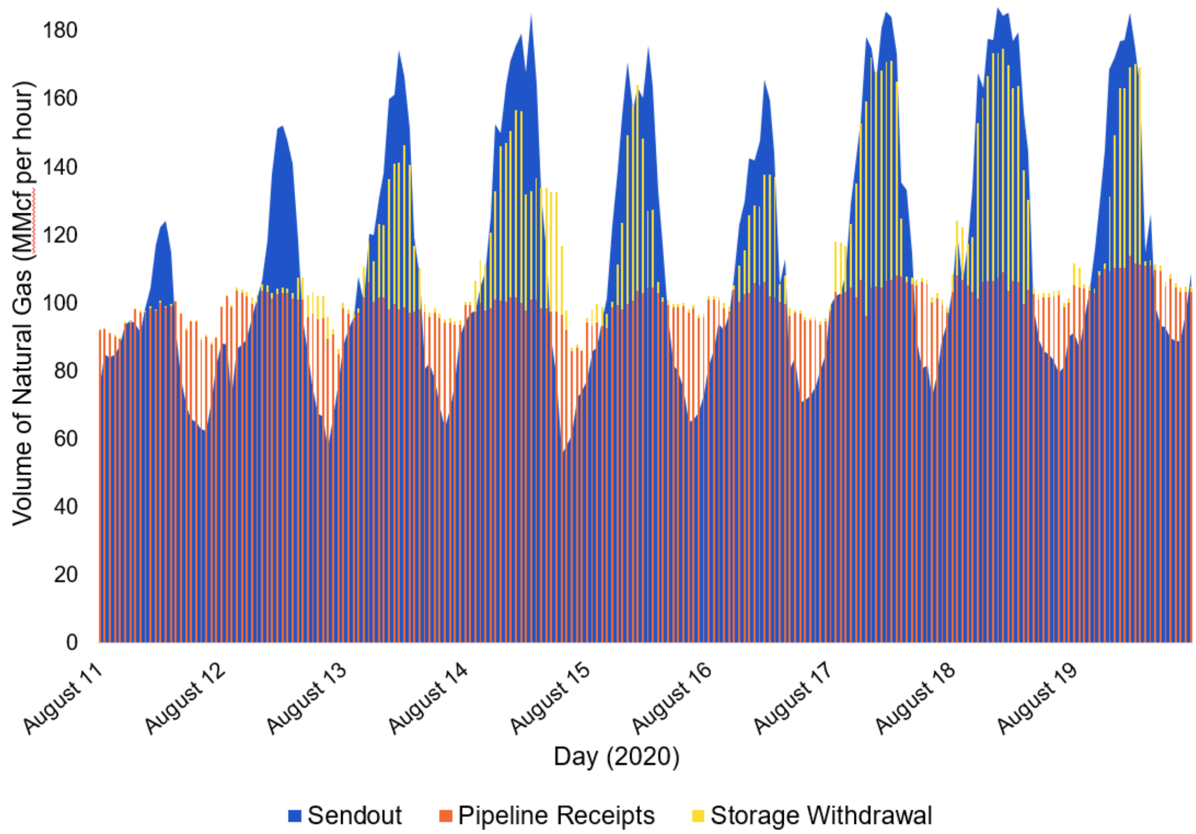
To meet the pressure on the CAISO system during the week of August 11, electric system operators turned to gas-fired generation facilities. To ensure that these generation plants had the natural gas supply to maintain the integrity of the electric grid, SoCalGas had to draw significantly on its gas system storage assets.

Figure 3-13 provides an hourly view of pipeline receipts into the SoCalGas distribution system, sendout, and withdrawals from storage. The blue vertical bars illustrate the hourly demand and sendout from the SoCalGas system. The orange vertical bars depict the quantities that were received into the system, which is generally received in steady hourly quantities over the course of the day. The yellow vertical bars above the receipts illustrate the volumes required to be withdrawn from storage on an hourly basis to meet the far more variable and changing intraday needs of electric generators, which exceeded the gas supplies arranged for delivery into the

[35] Batteries and coal contribute negligible amounts (± 100 MW) and are not shown within the figure.

SoCalGas system each day. The imbalance between daily pipeline receipts and sendout (mostly to serve the load of electric generators) was most significant on August 17 and 18, when sendout for each day was ~3.1 Bcf, while receipts were 2.5 Bcf, resulting in a deficit of ~0.6 Bcf daily, which was required to be made up by on-system storage.

Figure 3-13. Hourly Supply and Demand on the SoCalGas System



Source: Guidehouse, SoCalGas

From August 11 to 19, pipeline receipts on the SoCalGas system were approximately 100 MMcf per hour (2.4 Bcf per day/24 hours). In this same period, deliveries to SoCalGas customers exceeded 100 MMcf per hour during approximately 110 of 168 hours, or 65% of the time. August 11 was the only day SoCalGas was able to meet the peak delivery in excess of pipeline receipts through utilization of linepack (i.e., no storage withdrawal). On all following days, withdrawals from underground storage played a critical role when hourly consumption exceeded pipeline receipts.

Hourly withdrawals in excess of the equivalent of 800 MMcfd were experienced more than a dozen times between August 15 and 19. Those withdrawal rates were only possible with withdrawals from all SoCalGas' storage fields, including Aliso Canyon. The week of August 11, 2020, the totality of SoCalGas' system assets were employed to address the shortfall between abnormally high electric demand and low renewable energy generation experienced in Southern California.

Conclusion

Due to COVID-19-related impacts, C&I demand during this period was lower than normal. Although storage was critical to filling the gap between supply and demand, SoCalGas estimates that—had C&I demand been closer to average historic levels—it is likely that the capacity of the SoCalGas transmission and storage system would have been exceeded, which could have resulted in curtailment of electric generation. This is due to SoCalGas' planning standards and priority of services that are primarily focused on core customers, the SoCalGas tariff deprioritizes service to electric generators and allows curtailment during constrained/high demand periods. This situation is not unique to California, in other jurisdictions, electric generation, in the event of a curtailment, is given a lower level of prioritization compared to residential customers.

> *If the gas system was not able to fill the gap between abnormally high electric demand and low renewable energy generation to support the overall resilience of the electric system, Southern California would likely have experienced severe power outages during the system resilience event experienced in August 2020.*

The gas system fosters electric system reliability and serves as a resource that is capable of readily addressing unplanned or unforeseen events within the integrated energy system. When these resilience events occur, electric generators can experience large intraday swings in their need for gas supplies, often with little to no notice. In regions where the intermittent use of the gas system for electric power generation is a significant portion of total gas use on the system, this unpredictable non-ratable flow can stress the physical gas delivery system. Although the physical infrastructure including pipeline transportation and storage assets are in place and able to accommodate this type of intermittent usage, the underlying market framework and regulatory structure were not designed to provide this type of support service to the overall energy system. In general, the regulatory structure does not provide a means to construct and operate investments that provide resilience protection. That the gas system can provide this service demonstrates how resilience is a byproduct of the engineered reliability features of gas delivery system. The result being that the gas system and the gas LDC ratepayers provide this resilience service to the overall energy system without receiving compensation commensurate to its value.

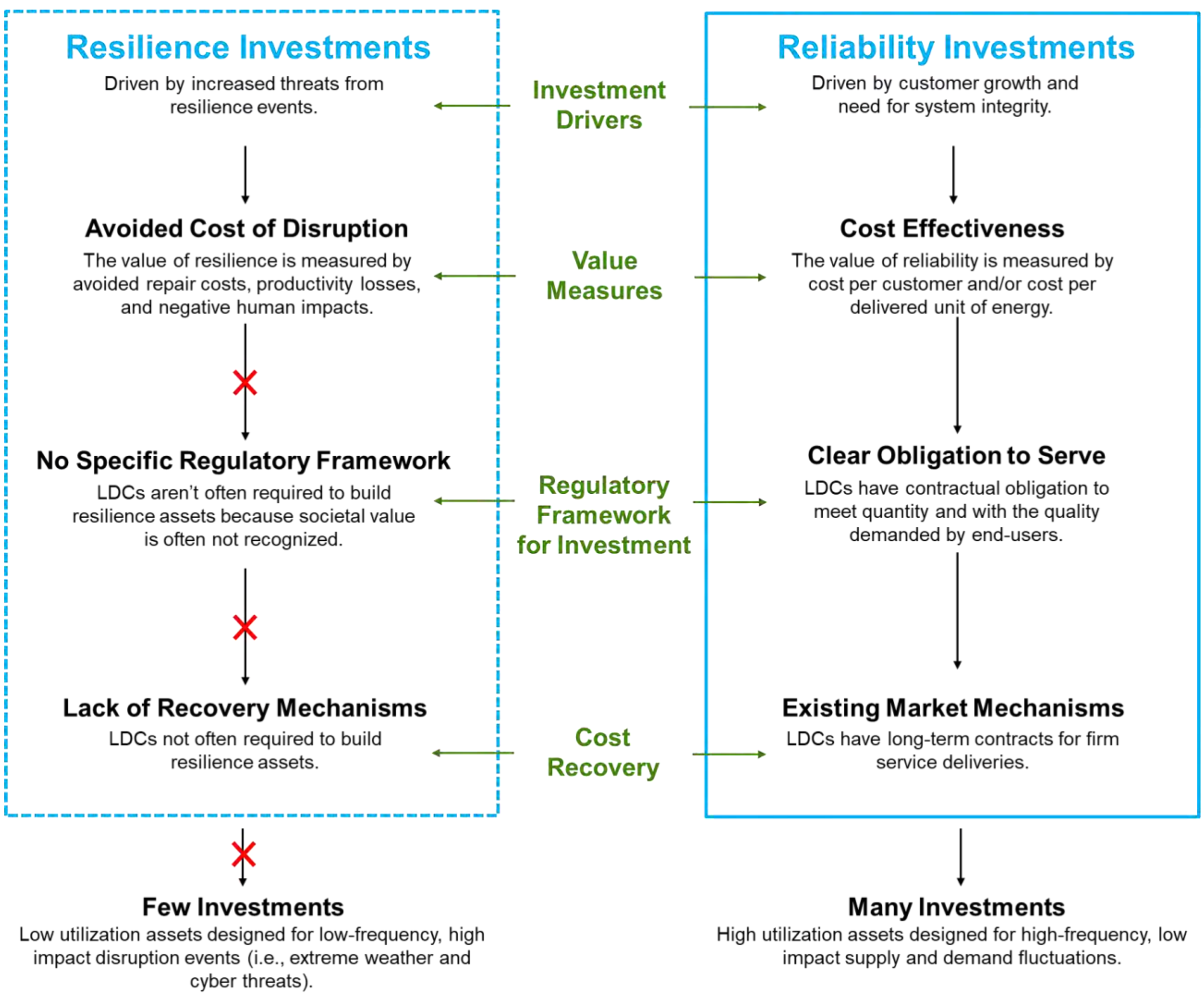
4. Current Regulatory, Policy, and Market Structures

The first half of this report established that the gas system provides resilience to the US energy system. The second half focuses on the regulatory, policy, and market structures that underpin the US energy market. This section explores the current state, including how these structures have developed and the challenges they create. Section 5 considers forward-looking considerations to ensure future energy system resilience.

4.1 The Difference Between Resilience and Reliability Investments

The current market economic framework is designed to support the development of physical assets with high utilization or those backed by long-term contracts. These assets provide reliability services to the energy system. Reliability assets often contribute to the resilience of the energy system as a byproduct, but they are not designed to meet the full needs of a resilience event. Figure 4-1 explores the differences between resilience and reliability investments.

Figure 4-1. Comparison of Resilience and Reliability Investments



Source: Guidehouse

4.2 Historical Context of Gas System Development

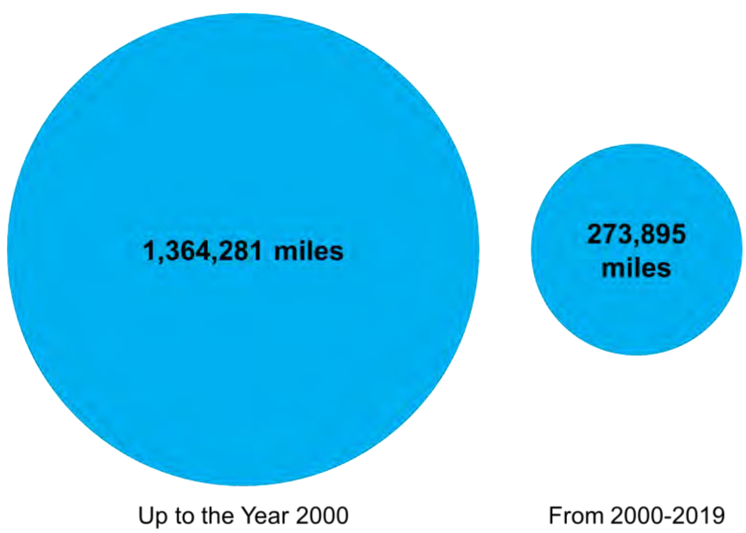
To fully understand some of the challenges in regulatory, policy, and market structures around the development and support for the use of natural gas as a resilience asset, it is necessary to understand the historical context around how these frameworks have developed. In this section, we consider the historical context of the development of the gas system and what implications that has had on the structure and the gas system's current support of energy system resilience.

Natural gas was first used in the early 1820s. However, lacking efficient transportation options, its usage was limited to powering light sources, usually close to natural gas wells. In the late 1890s, gas pipeline construction began and partnered with technological advances, this more efficient transportation of the resource fueled the growth of the US pipeline and connected natural gas wells to users—homes, businesses, and heavy industry. It was not until the late 1990s (really after 2000) that natural gas became a significant source of US electric power generation.

4.2.1 Residential, Commercial, Industrial Load (Pre-2000)

The majority of US natural gas gathering, transmission, and distribution pipeline infrastructure that exists today (approximately 83%) was built out prior to 2000, as Figure 4-2 shows. This infrastructure was built based on a paradigm of predictable and relatively stable demand from residential, commercial, and industrial loads—and stable investor returns. There are several mechanisms that pipeline companies and LDCs use to maintain the integrity of their systems in accordance with Federal law. Across the US, state utility commissions have approved infrastructure modernization programs and pipeline replacement programs to address aging infrastructure. A total of 41 states and the District of Columbia have adopted an approach to support the prioritization, financing, and execution of gas infrastructure upgrades. These programs not only increase the safety of the energy system, but also enhance the future resilience of the energy system.[36]

Figure 4-2. Incremental US Natural Gas Pipeline Additions

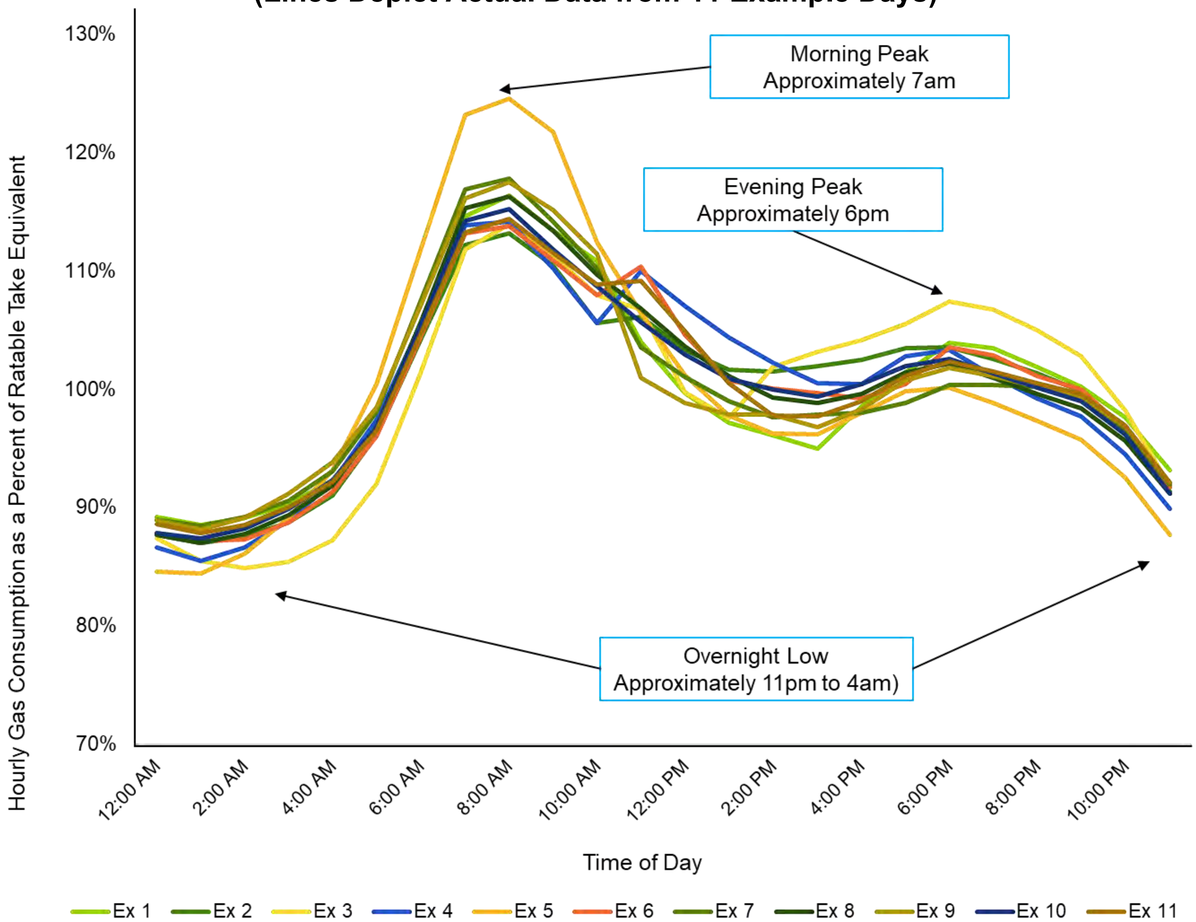


Source: Guidehouse, US Bureau of Transportation Statistics

[36] NARUC, January 2020. Natural Gas Distribution Infrastructure Replacement and Modernization.

The aggregate daily gas demand to serve residential, commercial, and industrial customers is predictable and relatively stable. Gas usage for these customers increases significantly in the morning before slowly decreasing over the course of the day. There is an additional, relatively minor, increase in the evening around dinner time before gas usage drops over the night. Figure 4-3 presents the aggregate load profile for these customers. The figure's y-axis indicates percent variation in hourly gas consumption as a percent of ratable take equivalent[37] and the minimum and maximum peaks only vary -16% to +25% from that daily average.

Figure 4-3. Aggregate Daily Natural Gas Load Profiles, for Residential, Small Commercial, and Industrial Customers (Lines Depict Actual Data from 11 Example Days) *



*Source: Guidehouse, Consumers Energy**

The gas usage pattern is predictable for these customer groups, even in varying climatic conditions. In colder conditions, the usage pattern features less volatility as demand for space heating is more constant throughout a cold day. In warmer conditions, the peaks and troughs widen, and the total daily usage is lower. The predictability of this trend enables gas LDCs to construct and operate the gas system and build new assets with a high degree of confidence in the use of those assets.

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[37] *Ratable take equivalent* refers to the comparable amount of gas consumed in one day on a levelized basis over a 24-hour period, i.e., in even 1/24th increments. This is further discussed in Appendix A, Section A.3.1.

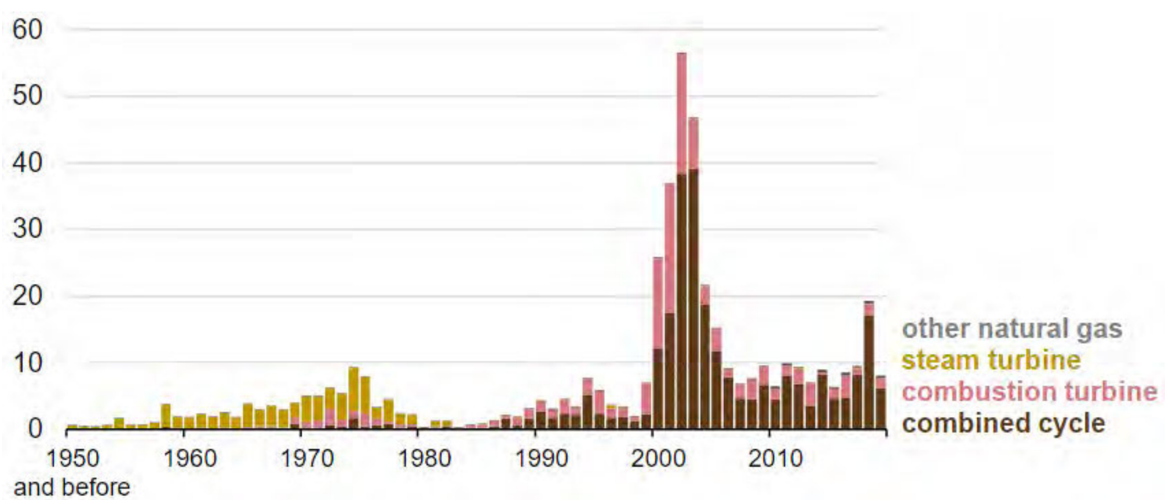
> *The gas system that serves the US today was built to serve the residential, commercial, and industrial sectors, where the relative predictability of usage over the course of a day (ratable takes) and throughout the year for these customer segments enabled LDCs to design, construct, and operate the gas system with a high degree of confidence in how the gas system would be used to serve demand.*

The entirety of the gas value chain's economic and operational framework is underpinned by this ratable system of supply and demand.

4.2.2 Gas-Fired Electric Generation (Post-2000)

When much of the current gas system was designed, the electric sector was a small component of overall demand. Between 1949 and 2000, gas-fired generation provided an average of just 16% of total electric power generation in the US on an annual basis. Since 2000, this has increased significantly. In 2019, natural gas accounted for 38% of US electric power generation and provided 43% of operating US electric power generating capacity.[38] Figure 4-4 explores this trend and shows that most of the growth in gas-fired generation capacity occurred between 2000 and 2020. More information on the role of natural gas in the electric power generation sector can be found in Appendix B.

Figure 4-4. US Gas-Fired Electric Power Generation



Source: US Energy Information Administration

4.3 Natural Gas in Electric Power Generation

There are critical differences in the way that gas-fired generation interacts with the gas system. This section explores those differences. In general, gas-fired generation plants fall into one of two classifications:

1. **High-capacity factor generation:** These low-heat rate/high-efficiency plants support electric power generation by operating often at close to full capacity 24/7.

[38] EIA. 2020. Electricity: Current Issues and Trends.

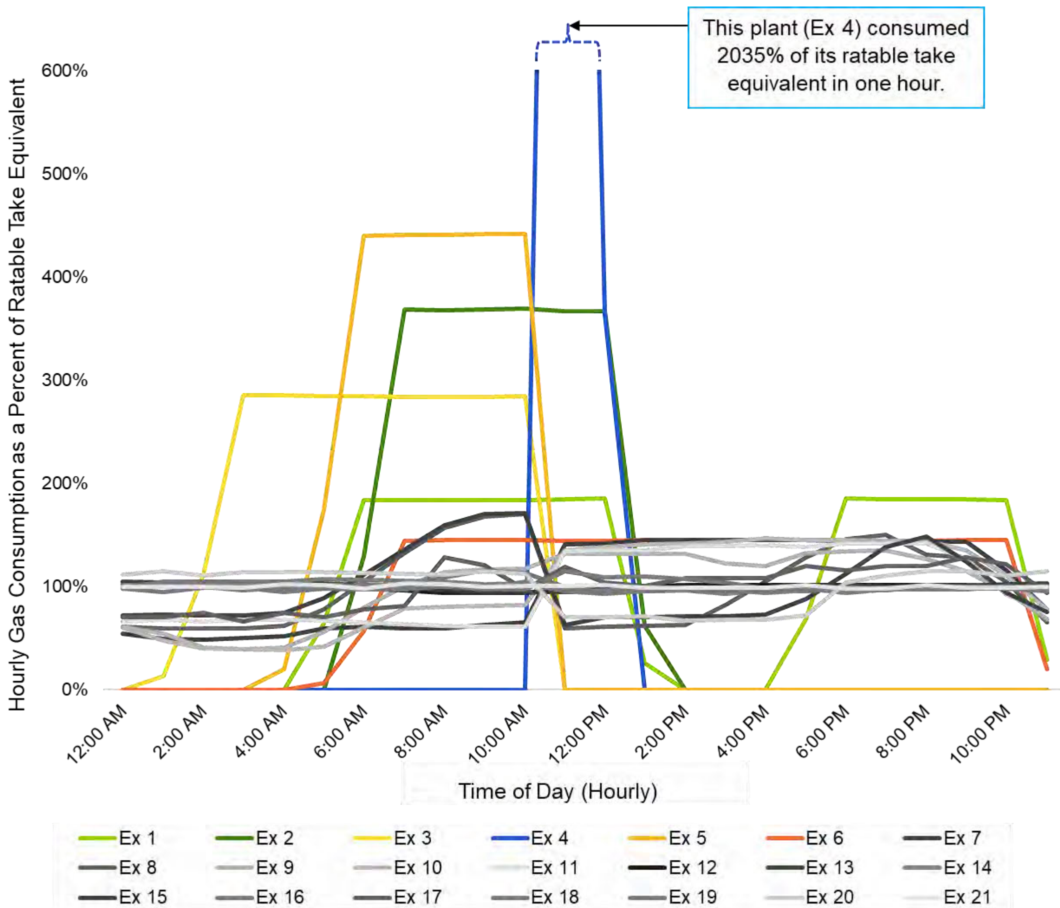
2. **Intermittent generation:** These plants serve as dispatchable resources for electric system operators, ramping their generation up and down quickly to fill the gaps between intermittent generation sources (such as renewable sources) and consumer demand.

4.3.1 Gas-Fired Electric Power Generation Load Profiles

Figure 4-5 illustrates the load profiles of six different gas-fired electric power generation plants over a period of 21 days. Gas load profiles of gas-fired electric power generation plants exhibit far more variance on a daily and hourly basis than the load profiles of residential, commercial, and industrial customers. In Figure 4-5, high-capacity factor generation plants are identified generally in gray (Ex 7 through Ex 21) and those serving intermittent generation capabilities are identified with varying colors (Ex 1 through Ex 6).

The load profile for high-capacity factor gas-fired plants (Ex 7 through Ex 21 in Figure 4-5) generally features a morning and evening peak, and the variation between the highest hour of usage and the lowest hour of usage from ratable take equivalent is 71% to -61%, similar in pattern to the load profiles for residential, commercial, and industrial customers but the magnitude of the swings are larger.

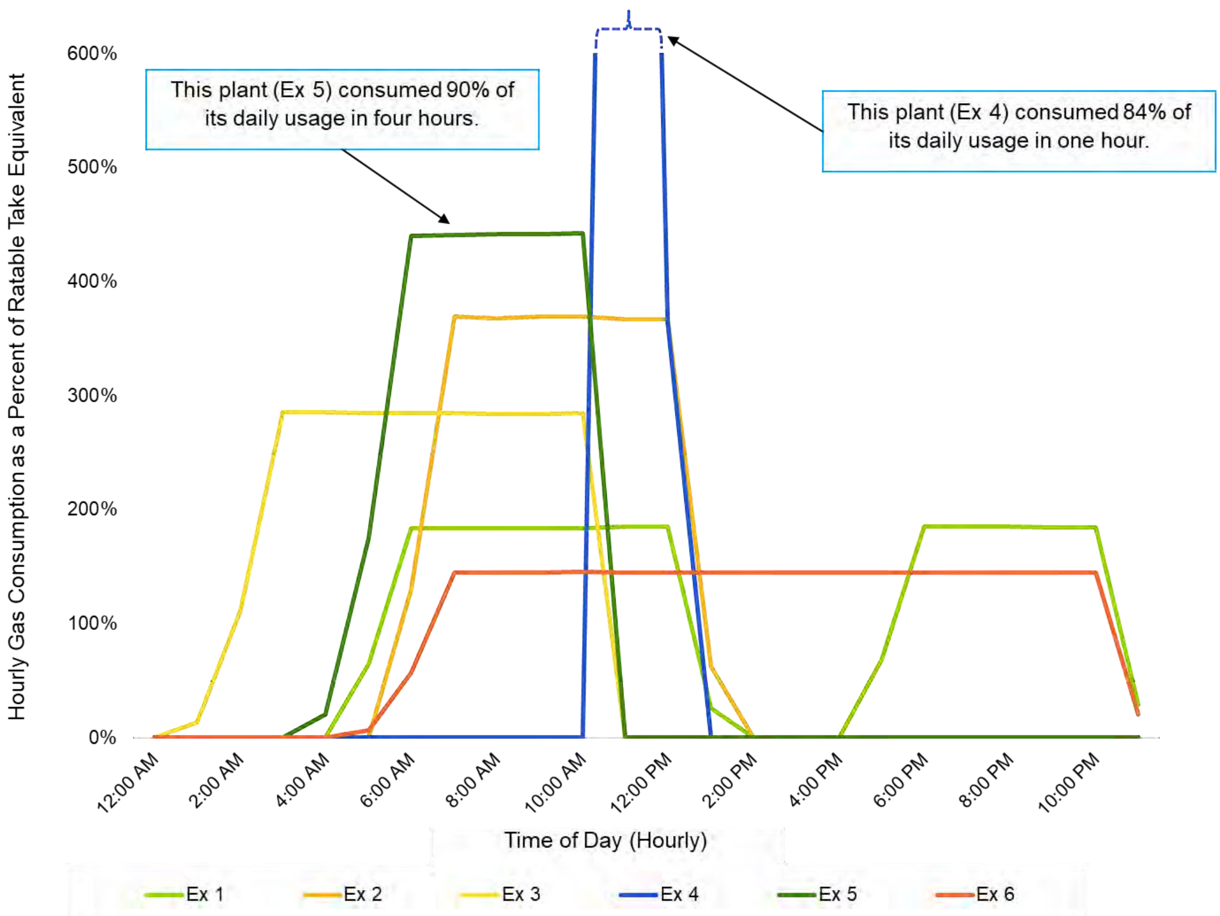
Figure 4-5. Daily Natural Gas Load Profiles for Gas-Fired Electric Power Generation (Lines Depict Actual Data for 21 Example Days, Data is Inclusive of Six Facilities)



Source: Guidehouse, Consumers Energy

Gas-fired plants that run intermittently exhibit a different load profile from the relatively predictable daily variation of high-capacity factor plants. In Figure 4-6, the high-capacity factor generation daily load profiles were removed to focus on the load profiles of intermittent gas-fired plants. The load profiles associated with these plants exhibit a high level of variability and intraday swings, as the plants quickly ramp up and down from their peak rates.

Figure 4-6. Daily Natural Gas Load Profile for Intermittent Gas-Fired Plants (Lines Depict Actual Data for Six Example Days, Data is Inclusive of Six Facilities)



Source: Guidehouse, Consumers Energy

The gas supply required by intermittent gas-fired plants is characterized by large volumes of fuel that are subject to a level of variability and intraday demand swings that are vastly different from how the residential, commercial, and industrial sectors consume gas over the course of a 24-hour period.

> *Intermittent gas-fired plants are primarily used to fill gaps between other intermittent generation sources (such as renewables) and customer demand for electricity. They are only capable of fulfilling this role because the gas delivery system enables the delivery of supply to serve the swings needed to provide such a quick-start response. Although the gas system fulfills these needs, the physical delivery system and the supporting market mechanisms and commercial terms that govern day-to-day operations were not designed for this type of usage*

4.3.2 Implications for the Gas Delivery System

Upstream pipeline deliveries to the gas distribution system occur at relatively steady hourly quantities throughout a day, but gas is not consumed in even hourly increments over the course of a day. Gas distributors have a variety of tools including linepack, storage, and mobile delivery capabilities to accommodate this intraday swing in demand and enable deliverability and respond to increases and decreases in consumption.

The gas transmission system is designed to accommodate the delivery needs of the predictable and low variability patterns required of residential, commercial, and industrial customers. Meeting the variable delivery needs of high capacity factor and intermittent gas-fired plants is a greater challenge as the gas consumption of these plants is much more variable, especially for intermittent gas-fired plants. Gas system operators supplement hourly pipeline receipts with linepack and storage withdrawals to maintain integrity and meet the needs of intermittent plants.

The gas distribution system's ability to provide this intermittent deliverability service is highly dependent on the amount of gas in the pipeline, the inventory levels in storage, the inventory in other storage assets, and contractual obligations to other customers. Providing service to gas-fired generators, particularly intermittent gas-fired generators requires coordinated planning from operators of the gas and electric systems.

4.4 The Regulatory Context

This section discusses how the current regulatory structures hinder the construction, utilization, and operation of new gas assets to serve resilience needs. Often, current regulatory structures tie the development of interstate pipeline and storage assets strictly to the needs of customers (producers, gas utilities, and other end users) willing to execute long-term firm service contracts. These do not easily support the construction, utilization, and operation of resilience assets that, by their nature, will be used infrequently to support low likelihood, high impact events. As a result, gas systems may not be appropriately compensated for the resilience services they provide.

Two critical principles often underlie the regulatory approval of infrastructure development:

- **Alignment between who benefits and who pays:** The ability to demonstrate how an asset provides a benefit to those who pay for its development is a standard principal of utility ratemaking.
- **The business case hinges on high utilization:** The construction and operation of most gas assets are founded upon the willingness to execute long-term firm service contracts; higher utilization translates to lower cost per unit.

This framework begins to break down when asset development activities or business model economics are not aligned with these principles. Applying these regulatory principals to the consideration of the construction, utilization, and operation of gas assets for resilience purposes, two key challenges are exposed:

- Current gas system resilience is a byproduct of reliability investments
- Gas systems may not be appropriately compensated for the resilience service they provide

The remainder of this section discusses these two challenges.

4.4.1 Current Regulatory Framework for Infrastructure Approval

To construct a new energy system asset, a gas utility must receive approval from its regulator, typically a state-level public utility commission. The investment is typically approved if the gas utility demonstrates the investment is prudent and serves the needs of its customers.

The principle of alignment between who benefits and who pays is applicable to regulating the expansion or new construction of interstate pipeline and storage infrastructure. A utility is responsible for the burden of proof of necessity on behalf of its customers. For interstate pipeline and storage assets, the burden of proof is on the market need demonstrated by customers who have executed precedent agreements.

The Federal Energy Regulatory Commission (FERC) regulates interstate pipeline and storage markets. Pipeline and storage operators seeking regulatory approval to construct or expand an asset must provide FERC with a demonstration of market interest to receive approval. FERC grants approval if this market interest can be demonstrated. Due to the long life of pipeline and storage assets, the regulators seek to balance the interests of customers with landowners and the public around environmental concerns,[39] as well as the financial viability of the project. Market interest is demonstrated in the form of customer execution of long-term firm service contracts, where firm service entails a right to a predetermined amount of capacity on the pipeline during the agreement period.

Natural gas utilities are regulated by state public utility commissions (PUCs). PUCs approve infrastructure investments based on the concept that the investment provides utility service and supports the utility's obligation to serve. Gas utilities enter long-term firm capacity contracts because they are required to fulfill an obligation to serve their customers, particularly during periods of peak usage. For example, a gas utility with a significant winter peaking load will subscribe to a long-term contract to serve that load even if its firm rights to pipeline capacity will be underutilized in the summer—resulting from the utility's obligation to serve.

> *A fundamental underpinning of regulatory approval for interstate pipeline and storage construction is the demonstration of market need, as supported by customer willingness to enter long-term contracts for firm capacity.*

When pipeline or storage customers are not willing to enter long-term firm contracts, the market structure creates barriers to obtain the right to a predetermined capacity that is not subject to a prior claim from another customer. This is an issue for certain gas-fired electric power generators. Electric power generators profit if their cost of producing power (fuel plus operations and maintenance) is lower than the average price they sell electricity. Given most gas-fired powered generators are unable to store fuel onsite, they must rely on quick response delivery of natural gas, resulting in two unequal options:

- **Sign a long-term firm contract.** While an option, it is not typical because it could increase the cost such that it is not competitive with other sources of generation, i.e. coal and fuel-oil plants that can store fuel onsite, and solar and wind power that do not require fuel input.
- **Sign a secondary or interruptible contract.** Most gas generators take this action because the economics are more favorable. Interruptible capacity refers to pipeline transportation capacity that is available when the holder of the firm right to this capacity

[39] FERC. 2020. "The Natural Gas Pipeline Application Process at FERC."

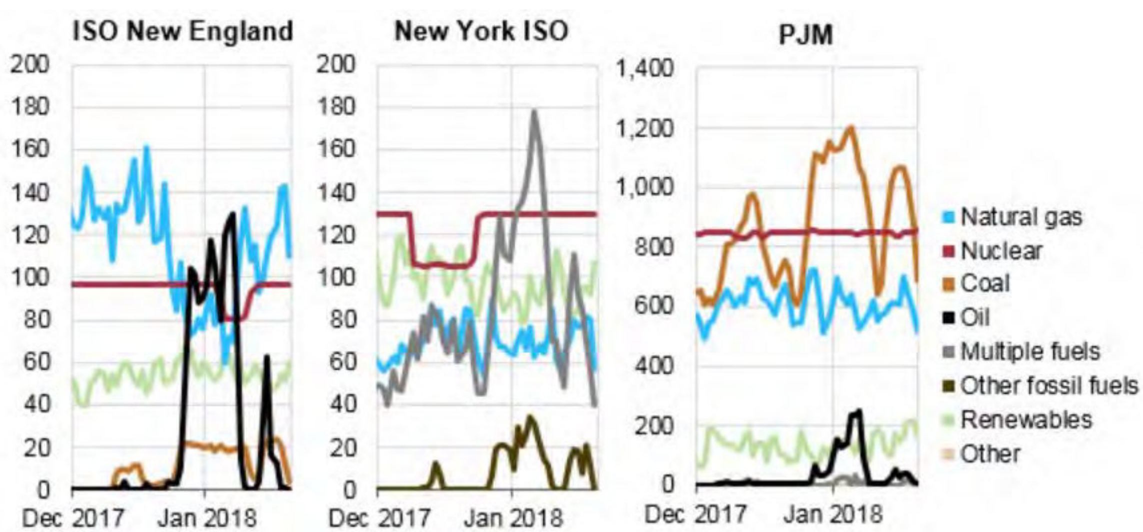
is not using it. The risk is that the pipeline or storage capacity may not be available when it is needed.

4.4.2 Regulatory Framework and Implications to Resilience

In periods of peak usage (e.g., during periods of high use), holders of firm pipeline transportation are likely to use their full allotment of capacity, leaving little to no capacity to secondary or interruptible contract holders. In these periods, gas-fired generators without firm capacity will likely be constrained. During periods of high use, a constrained gas pipeline can create economic or operational conditions that lead to increased fuel switching to oil-fired or dual-fuel generation. This has caused and can cause risk that electric generators lose the ability to serve peak electric load when customer demand for gas supply is also at its peak. This constraint is further illustrated in Figure 4-7.

Figure 4-7 details fuel switching in three electricity markets in the northeast (New England, New York, and PJM) during the January 2018 bomb cyclone. In early January, as the Northeast experienced the cold weather related to the bomb cyclone, demand for electric power generators increased as natural gas transportation was constrained.

Figure 4-7. Comparison of Electric Power Generation During the January 2018 Bomb Cyclone[40]



Source: US Energy Information Administration

- In ISO New England (ISO-NE), oil generation jumped from almost nothing to a high of 36% of the daily generation mix. In comparison, gas-fired generation decreased from approximately 50% to less than 20% of supply.
- On New York ISO's (NYISO's) system, the output of dual-fuel generators, mostly gas-fired generators that can switch to fuel oil, and other fossil fuel generators rose significantly.
- In PJM, oil and coal generation increased while gas-fired generation remained consistent.

[40] EIA. 2018. Northeastern Winter Energy Alert.

Gas-fired generation did not make up the required increase in demand to meet the increased electric power generation needs during the 2018 bomb cyclone event. The structure of the underlying electricity markets, specifically the reliance on unused pipeline capacity for fuel delivery for gas-fired generation to maintain competitiveness, poses a challenge to investments in gas infrastructure in the electricity markets such as ISO-NE, NYISO, and PJM.

4.4.3 Current Gas System Resilience Is a Byproduct of Reliability

The current model for developing gas infrastructure supports construction of assets that support reliability of service and that can be underpinned by long-term contracts. This model has been supportive for maintaining the resilience of the gas system, but it must be recognized that the model does not reflect how the gas system will be operated in the future. It also does not support construction of assets that support resilience requirements.

As demonstrated by the case studies, gas infrastructure provides resilience benefits to the entire energy system. However, the strength of the current gas system is a byproduct of an outdated regulatory system, optimized around daily reliability instead of long-term resilience. Fortunately, the overlap between the two outcomes is considerable enough that the energy system currently experiences a reasonable level of resilience. However, the current regulatory structure does not provide a means to construct and operate investments primarily for resilience. As the transformation of the energy system continues, we anticipate the need for more resilience and a changing mix of assets required to provide that service. The manner in which this energy system is regulated and managed is becoming outdated; thus, an update is necessary to maintain resilience in the evolving future energy system.

4.4.4 Gas Systems Are Not Appropriately Compensated for Resilience Services

From a regulatory perspective, LDCs have an obligation to serve and must develop supply and transportation plans to provide gas reliably at the lowest sustainable cost. Typically, gas distribution utilities do not procure more gas supply than necessary for a given day and instead use storage and linepack to balance intraday supply and demand. In most cases, LDCs cannot secure regulatory recovery to procure and store additional gas supply for low likelihood, extreme climate events beyond that incorporated in reserve margin planning. When a customer draws significantly more gas from the gas system than its average demand, this additional supply comes from gas stored that is already allocated to another customer.

> *Any incremental supply that is available to serve electric power generation on short-notice will be gas that has been reallocated from other customers unless the pipeline or LDC offers a no-notice service.*[41]

Some interstate pipelines and gas distribution companies offer no-notice service on a firm basis by dedicating pipeline and storage infrastructure to support the delivery of gas on short notice—no-notice service is typically supported via interstate pipeline tariffs. An electric power generator may pay the cost of expansion of pipeline or storage assets to support the maximum volume consumed. Example 4 (page 57) is a good illustration of this scenario.

In other cases, providing gas supply on short notice to serve resilience events is limited by several features of the gas delivery system. From a physical perspective, the incremental supply

[41] No-notice service refers to the delivery of natural gas on as-needed basis, without the need to precisely specify the delivery quantity in advance (quantities within contract entitlements).

consumed on an intraday basis needs to be in the pipeline at the moment the electric power generator requires delivery throughout the period that the electric generator is producing power. The accommodation of non-ratable flows in the gas system depends on how other shippers use their contracted entitlement in the pipeline and the operational flexibility of the pipeline (e.g., line pack and storage availability). If the pipeline is already full, extreme spikes in demand from non-ratable users may not be met.

The LDC delivery system was not designed to provide large volumes of no-notice service to the electric power generation sector. However, in many circumstances, LDCs provide non-ratable service when capacity is available and when it does not threaten operations. In these cases, the gas system supports the energy system's overall resilience but is not adequately compensated for its service. This lapse in compensation occurs because an additional service is being provided with assets that were not designed for the circumstances.

4.5 Impacts on Consumers

This section considers the varying level of the impact of the findings on the current state on gas ratepayers and electric ratepayers. At a high level, gas ratepayers are more closely aligned with gas system resilience investments than electric ratepayers, as there is no misalignment around who benefits and who pays. Electric system ratepayers, who benefit from the gas system through gas-fired generation have greater misalignment with the development of gas system resilience investments.

4.5.1 Gas System Resilience to Benefit Gas Ratepayers

LDC customers benefit from the resilience provided by assets that are built to provide reliability. Assets are built to serve gas ratepayers. There is a disconnect between who benefits and who pays. The resilience byproduct of these assets benefits these customers. Construction of an asset that is primarily designed for resilience is problematic, because:

- **Lack of a Regulatory Framework:** Resilience of the gas system is not a current regulatory requirement.
- **Lack of Metrics:** Unlike reliability, which can be measured, resilience does not lend itself easily to quantification. For example, value of avoiding the socioeconomic consequences and costs of a prolonged disruption is difficult to measure.

The lack of a regulatory framework and the difficulty of measuring the value complicates the prudency review and cost-effectiveness evaluation of an asset whose business purpose is resilience. As such, reliability drives investment in gas infrastructure. Assets are designed and approved to meet reliability requirements driven by projected gas supply needs and delivery requirements for peak day usage based on historical data. A specific regulatory mechanism to support cost recovery for gas assets whose primary service is to serve resilience events does not exist and needs to be developed.

4.5.2 Gas System Resilience for Electric Ratepayers

There is a larger disconnect between current market structures and the development of resilience assets when the beneficiaries of gas system reliance are not direct gas system customers, such as electric market customers.

- **Difficulty to recover costs across complementary energy markets:** While there is a connection between the resilience of the gas and electric systems, there is no mechanism for electric market participants to collect revenue or provide cost recovery for investments in gas system resilience.

The gas delivery system was not constructed to handle the increasing frequency of large intraday swings in service demand by gas-fired generators that serve intermittent load. As discussed in Section 4.3.2 and as described in Case Study 6, the gas system accommodates the non-ratable flow of the electric sector on a best-efforts basis. In many cases, pipeline transportation arrangements, tariffs, and coordination efforts exist between an LDC and specific electric power generators. However, these are generally workarounds that do not address the core issue: the current state market framework was designed to promote reliability and does not support the construction of assets whose primary function is to serve resilience, especially when the beneficiaries of that resilience are outside of the gas infrastructure-ratepayer ecosystem (i.e., the electric sectors' customers), nor does it fairly compensate the LDCs as the provider of these resilience services.

To further highlight the cost associated with the development of resilience assets, in Example 4 we discuss a gas infrastructure project specifically designed to serve the resilience needs of the electric sector. This example illustrates the benefits that the gas system can provide to the overall energy system when there is alignment between who pays and who benefits and there is a long-term contract to support development.

Example 4. Gas-to-Power Coordination

Portland General Electric (PGE), an electric utility in Oregon, has traditionally relied on hydroelectric generation resources to provide electric system flexibility. However, it sought new ways to achieve flexibility to meet the expansion of solar and wind generation capacity. PGE needed an efficient technology capable of quick-starting, as well as fast ramp-up and ramp-down rates to fulfil the grid's need for flexibility. PGE constructed a 220 MW electric power plant to provide intermittent power during winter and summer periods, as well as load following and renewable integration throughout the year. The plant can ramp to full load in less than 10 minutes.

To assure deliverability of natural gas to accommodate this quick start-up time, PGE partnered with NW Natural, an Oregon-based LDC, to contract for no-notice storage service. To provide this service, NW Natural embarked on a $149 million project that included a 13-mile gas pipeline, a compressor station, and a 4.1 Bcf expansion of the NW Natural' North Mist natural gas storage reservoir. Through this storage service, PGE can draw on its natural gas resources from NW Natural's facilities in Mist, Oregon to meet its fueling needs and rapidly respond to peak demand and variability of wind, hydro, and solar generation. The facility is contracted for an initial 30-year period with a renewal option of up to 50 years beyond that.

Currently, no specific compensation mechanism exists for the resilience services that gas-fired electric power generation provides the electric sector. In the future, as the percentage of electricity generation from intermittent renewable sources increases, the volume of natural gas used for electric power generation may decline; however, in responding to resilience events the necessity of the services provided by gas-fired electric generators may increase. As current compensation models for the gas system serving the power generation sector are tied to the volume of gas delivered to the facility, there becomes an increasing disconnect between the value of the services provided and associated remuneration for said services.

> *Reliability assets are designed and economically justified based upon historical averages and relatively stable utilization. Resilience assets are essential to operation under infrequent and extreme conditions. The benefits of their existence often extend beyond the energy system for which they were designed, i.e., resulting in a greater socioeconomic benefit such as reduced economic loss resulting from an extreme event.*

5. Ensuring A Resilient Future

The energy system of today will not be the energy system of tomorrow. Decreases in the cost of technologies and increasing pressures to decarbonize the energy system are manifesting in increasing levels of renewable generation, a more distributed generation profile, and a less carbon intensive energy supply—there is some indication that certain versions of this future may have negative impacts on energy system resilience.

In a recent review of the root cause of CAISO outages during the August 2020 heatwave, one of the three factors identified was:

> "*In transitioning to a reliable, clean and affordable resource mix, resource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours. This makes balancing demand and supply more challenging. These challenges were amplified by the extreme heat storm.*"[42]

As the resilience of the gas system grows in importance, cost recovery mechanisms need to be developed to support investments in assets that strengthen resilience. These cost recovery mechanisms should define the resilience requirement for both gas and electric ratepayers.

5.1 Lessons from Others

This section details key lessons learned from recent regulatory and legislative activities governing resilience in the electric, water, and healthcare sectors. These lessons highlight some opportunities that may exist to develop regulatory structures to support gas resilience investments.

5.1.1 FERC Order 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators

FERC Order 841,[43] issued in February 2018, directed regional grid operators to remove barriers to the participation of electric storage in wholesale markets. The order creates a legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs. Order 841 was upheld in a federal appeals court decision in July 2020 that declared FERC has jurisdiction over how energy storage interacts with the interstate transmission markets it regulates, even if those energy systems are interconnected with state-regulated electric distribution grids.

> *By directing regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage, Order 841 affirms that storage resources must be compensated for all services provided and moves toward leveling the playing field for storage with other energy resources.*

A key component of the ruling is that "many participation models were designed for traditional generation resources—resulting in limitations or barriers to participation, which constrain competition,"[44] because novel resources technically capable of participating are precluded from doing so as they are forced to operate under participation models designed for existing

[42] CAISO. 2020. Preliminary Root Cause Analysis Mid-August 2020 Heat Storm.
[43] FERC. 2018. Order 841.
[44] US Court of Appeals. 2020. On Petitions for Review of Orders of the Federal Energy Regulatory Commission.

technologies. Energy storage resources (ESRs) such as batteries are especially affected by participation barriers because they have “unique physical and operational characteristics” distinct from traditional resources: ESRs can “both inject energy into the grid and receive energy from it.”

Although this order has limited direct applicability to the natural gas market, it does provide evidence that there are avenues to adapt the current market framework for valuable emerging technologies. Moreover, FERC Order 841 recognizes that the energy system is being used in a different way today than the current regulatory framework envisioned. The acknowledgment that the regulatory framework needs to be reconsidered to remove participation barriers supports the durability of the electric system.

5.1.2 FERC: ISO-NE, Cost-Recovery for Critical Infrastructure Protection (CIP)

Recent FERC orders approving cost recovery for CIP in the electric system showcase how the appropriate cost recovery mechanism can be designed. Federally mandated CIP requirements for electric systems assign protection standards at the low, medium, and high level, with higher standards carrying higher compliance costs. Left unresolved, however, was how generators in wholesale markets would recover the costs of compliance that cannot be competitively offered into the energy and capacity markets. This is because more stringent CIP requirements that result in higher compliance costs provide a disadvantage to a generator that is competing with a generator with lower compliance costs. In May 2020, FERC issued an order approving a proposal submitted by ISO-NE[45] to permit the recovery of incremental costs incurred when low-impact energy systems are reclassified as medium impact energy systems. The order permitted ISO-NE to allocate and collect those costs from transmission customers and disburse the funds to the pertinent facilities.

The concept behind CIP provides several lessons for the consideration of creating cost-recovery mechanisms to support resilience in the natural gas sector. The first is that there are examples in energy markets where resilience is legally mandated. Second, although these mandates can be a source of economic disadvantage to market participants in deregulated energy markets, FERC has approved RTO designed cost recovery mechanisms that socialize the costs.

FERC has mandated a set of protections for critical infrastructure in recognition of the vital role that the electric system plays in supporting the livelihoods of Americans and commerce in the US. The FERC CIP requirements can be viewed as a mandatory resilience requirement with a defined, measurable set of standards.

5.1.3 Energy Resilience in the Water Sector

Water utilities and their regulation offers key lessons on regulatory innovation and resilience. On September 13, 2008, Hurricane Ike made landfall on the upper Texas coast, causing significant damage. Millions of customers lost power, including 99% (more than 2.1 million) of CenterPoint Energy’s[46] customers. A critical pumping station that enables delivery of approximately 75% of Houston’s water supply was one of the casualties and was without power for approximately 10 days—Houston nearly had to declare a water emergency as a result.

[45] FERC. 2020. Docket No. ER20-739-002.

[46] CenterPoint Energy is the electric utility serving the Houston Area.

The Texas legislature enacted legislation[47] in 2015 mandating that water and wastewater treatment facilities have emergency backup power. The requirement also established a definition of resilience: duration at least equal to the longest power outage on record for the past 60 months, or at least 20 minutes, whichever is longer.

In addition, the America's Water Infrastructure Act (AWIA), passed by the US Congress in 2018 and reauthorized in May 2020, requires community water systems to conduct a risk and resilience assessment and develop an emergency response plan (ERP). The ERPs need to focus on more than merely being able to respond. They must include risk mitigation actions such as alternative source water, interconnections, redundancy improvements, asset hardening, and physical and cybersecurity countermeasures if and as justified through assessment. More specifically, the AWIA requires the following:

- Strategies and resources to improve the durability of the energy system, including physical security and cybersecurity.
- Plans and procedures that can be implemented, and identification of equipment that can be used, in the event of a malevolent act or natural hazard that threatens the ability of the community water system to deliver safe drinking water.
- Actions, procedures, and equipment that can obviate or significantly lessen the impact of a malevolent act or natural hazard on the public health and the safety and supply of drinking water provided to communities and individuals, including the development of alternative source water options, relocation of water intakes, and construction of flood protection barriers.
- Strategies that can be used to aid in the detection of malevolent acts or natural hazards that threaten the security or resilience of the energy system.

5.1.4 Energy Resilience in the Healthcare and Emergency Response Sectors

In 2012, Hurricane Sandy made landfall on the US coastline near Atlantic City, New Jersey, with winds upwards of 80 mph. The storm killed over 100 people, flooded coastal cities, destroyed structures, and tore down power lines. As the hurricane devastated the coast, 8.5 million people in 15 states lost power. The widespread power outages severely impacted medical facilities, leaving society's most vulnerable people in life-threatening situations.

Hospitals in New Jersey were forced to evacuate patients after floodwaters damaged backup generators needed to run elevators, lights, and ventilators. Transporting critically ill patients resulted in the loss of life and highlighted the need for more resilient solutions.[48] The total socioeconomic impact of Hurricane Sandy was also enormous, resulting in economic losses ranging from $27 billion to $52 billion.[49] According to the Executive Office of the President in

[47] Texas Administrative Code. 2015. Rule 217.63: Emergency Provisions for Lift Stations.
[48] Modern Healthcare. 2012. *Left in the dark: Seven years after Katrina, Sandy is teaching hospitals more lessons on how to survive nature's fury*.
[49] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

2012, “these costs of outages took various forms including lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid.”[50]

In response, legislation arose from the crisis. Assembly Bill 1561, the New Jersey Residents’ Power Protection Act,[51] was passed in 2015, which requires “medical facilities, pharmacies, first aid squads, fire stations, gas stations,’ and newly constructed grocery stores all have backup generators.” These generators are expected to run for 96 hours in case of emergency. Additionally, generators must activate within 10 seconds and be inspected weekly. [52]

Senate Bill No 854 was also approved after the storm. It mandates healthcare facilities and retirement homes install emergency electric power generation should the need arise.

New Jersey’s legislation focuses on investing in resilience and is impactful for the community and the economy. The legislation exemplifies the growing acceptance of the need for a resilient energy system. In the form of backup generation, the strength of the energy system can withstand shocks and protect vulnerable community members. It will mitigate the emergency costs hospitals face over time, “saving the economy billions of dollars and reducing the hardship experienced by millions of Americans when extreme weather strikes.”[53]

5.2 Key Opportunities

Across the gas delivery value chain, the use of existing infrastructure assets is shifting. This shift in usage will undermine the current and future economics of how assets are compensated and limit the development of resilience-focused assets.

- **High-pressure intrastate and interstate pipelines** are developed based upon long-term agreements supported by shippers. Shippers are contract counterparties who provide the economic framework for development of pipeline infrastructure assets. These shippers have historically derived economic value from projects using high load factor ratable forecasts. In the past decade, most material projects were supported by a combination of electric power generation projects or increasing demand from LDCs. Primarily, these have been FERC regulated assets and regulatory approval is based upon a demonstration of demand by the referenced shippers. As utilization of gas-fired generation shifts due to the advent of more renewables and utility demand moderates under decarbonization pressure, forecasted utilization is likely to be significantly lower. As the use of the gas system changes, the way gas service is charged needs to change as well.
- **Storage assets** provide significant resilience benefits. Some utilities have the benefit of on-system storage due to the geologic formations being within the operating jurisdiction or they use aboveground storage assets. Other utilities subscribe to services from storage owners and operators upstream of city gates. Historically, the economic drivers for storage were seasonal pricing differentials and balancing services provided to the integrated gas infrastructure system. In the future state, these assets will continue to provide seasonal and long-duration supply services. Storage is an important resilience asset and will continue to be essential to an integrated energy system. The economics of legacy seasonal pricing

[50] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.
[51] State of New Jersey. 2014. *Assembly Bill No. 1561.*
[52] Facilities Net. 2013. *NFPA 110’s Fuel Requirements Can Help Guide Backup Power Plan For Hospitals*.
[53] Executive Office of the President. 2013. *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*.

differentials and balancing services may not provide sufficient revenue to encourage continued development and maintenance of these critical assets. If storage owners and developers were provided revenue for providing resilience benefits, however, the economic framework would sustain the availability of these necessary assets.

- **Distribution systems** have special duty assets including peak shaving storage, LNG storage, and non-pipeline solutions that provide resilience benefits. These assets historically have been designed to meet design day peak demand based upon historical heating degree days. However, as noted in the case studies, climate events create operating stress on existing gas systems. Like the interstate gas systems, the high frequency, high utilization economic framework that was used to justify investments in these legacy assets is not fit for stimulating future investments in a mix of assets that is becoming more intermittent.

The gas system is highly resilient and plays a critical role in supporting the stability of the overall energy system. Current regulatory, economic, and policy frameworks are not conducive to creating the vibrant energy system of the future. The gas and electric sectors are fortunate that the energy system designed to provide reliability has provided resilience benefits. However, the resilience benefits currently enjoyed are a regulatory byproduct and will not serve the needs of the future energy state.

6. Conclusions

The transformation of our energy system is well underway, driven by changes in the cost and availability of new technologies and increasing political and social pressure to decarbonize. The way energy is generated and used is changing rapidly, moving from a one-way power from centralized generation to end customers to a multidirectional network supporting two-way energy flows. As the energy system migrates to one increasingly powered by intermittent renewable sources, it also experiences increasingly frequent and intense climatic events—together these fundamental drivers are creating ever increasing operating stress on the energy system.

As discussed throughout this paper, the gas system is currently providing resilience benefits to the entire energy system. But, the strength of the current resilience is a byproduct of a regulatory environment that has valued investment in a reliable, ratable, and safe set of assets designed around a legacy demand forecast and historical heating degree day planning. As the transformation of the energy system continues, we anticipate a need to place a greater focus on resilience and a re-evaluation of the diversity of assets providing that service.

Full utilization of resilience assets is infrequent by nature. Yet, when a resilience service is demanded it is an essential product of the energy system and key to mitigating catastrophic risk and limiting socioeconomic costs to customers and communities. Utilities, system operators, regulators, and policymakers must make informed decisions to identify an economic framework to incent investments in resilience assets required to support a vibrant and strong future energy system. Resilience should be an energy system requirement like safety and not a byproduct of the existing framework.

6.1 Implications for Policymakers and Regulators

Looking into the future, evolving technology and the speed of transformation of the energy system will require a different economic and regulatory framework to support the appropriate mix of assets and fair compensation for continued investment. Achieving this is easier said than done. It will require a realignment of the valuation and cost recovery mechanisms that currently define the development of the US energy system.

Energy system resilience needs to be defined as a measurable and observable set of metrics, similar to how reliability is considered. To design a truly resilient system requires an ability to measure, evaluate, and optimize the benefit. Resilience needs to be considered as another dimension of system planning, similar to the way that reliability is considered today.

Resilience solutions must be considered from a fuel-neutral perspective and across utility jurisdictions, requiring electric, gas, and dual-fuel utilities to work together to determine optimal solutions. As this paper clearly illustrates through the case studies, when low likelihood, high impact events impact our energy system—the energy system responds through integrated responses that rely on fundamental characteristics of a diversity of assets. Energy system resilience solutions cannot be engineered through a siloed approach that considers only a portion of the energy system, they must consider the opportunity and value that can be brought to the energy system across a diversity of assets.

Methodologies need to be built for valuing resilience, such that it can be integrated into a standard cost-benefit analysis. Value must consider the avoided direct and indirect costs

to the service provider, customers, and society. LDCs and other pipeline infrastructure providers are not fully compensated for the true value of resilience services they provide to the overall energy system. Because the resilience of the gas system is largely a function of the reliability of the gas system, the true cost of resilience (i.e., return of and return on capital invested in physical infrastructure) is treated as a sunk cost. In other words, ratepayers are paying for reliability and enjoying resilience as a benefit—a disconnect that will become increasingly evident as extreme events become more frequent and the share of intermittent renewable generation increases.

In addition to the legacy evaluation criteria that determine cost-effectiveness, policymakers and regulators need to consider ways to evaluate the socioeconomic benefits and avoided costs to the communities resulting from a resilient energy system.

- What is the cost to the community of catastrophic loss of service during a climate event?
- If energy is not available to essential services can this value this be considered by analysis that primarily focuses on the costs per MMBtu or kWh?
- What level of insurance would these communities be willing to pay to have a future energy system that is robust enough to recover quickly and vibrantly from man-made and climate-driven events?

> *Resilience assets mitigate exposure to catastrophic impacts to the communities they serve and should be viewed as an insurance policy to limit risk.*

Cost recovery should be spread over the entire energy system when considering endorsement of capital projects for resilience assets. Further, cost recovery stimulated by utilization is not an appropriate metric for low load factor usage associated with low likelihood, high impact future scenarios.

6.2 A Call to Action

The development of a new regulatory framework will require innovation and collaboration from utilities, system operators, regulators, and policymakers to identify workable solutions that are fit for purpose and tailored to the requirements of regional markets. Preparing the future state to respond effectively to the current transformation requires the communication, coordination, cooperation and collaboration with all industry partners and stakeholders to identify, develop, and implement solutions.

Any future actions undertaken by regulators and other stakeholders should be evidence-based, fuel neutral, and based on objective criteria that scrutinized by all stakeholders. FERC has left it to the RTOs to assess how to best enhance the resilience of the power system and recognizes that solutions to improve gas/power resilience will need to be resolved at the RTO level, however federal direction may also be needed to coordinate productive discussion and facilitate collaboration.

Recent FERC regulatory activity and RTO-led stakeholder planning engagements indicates a precedent for this type of cross-industry collaboration. This activity suggests that the innovation required to address shifting requirements for energy system resilience and facilitate cost recovery for resilience assets is not only possible but achievable.

State PUCs have a vital role to play as well. As the primary regulator of LDCs, PUCs are charged with ensuring customer protection, fostering competition, and promoting high-quality infrastructure. Moreover, solutions to the issues identified in this report will require locally identified solutions that are tailored to the unique needs and circumstances of individual LDCs and the regions they serve.

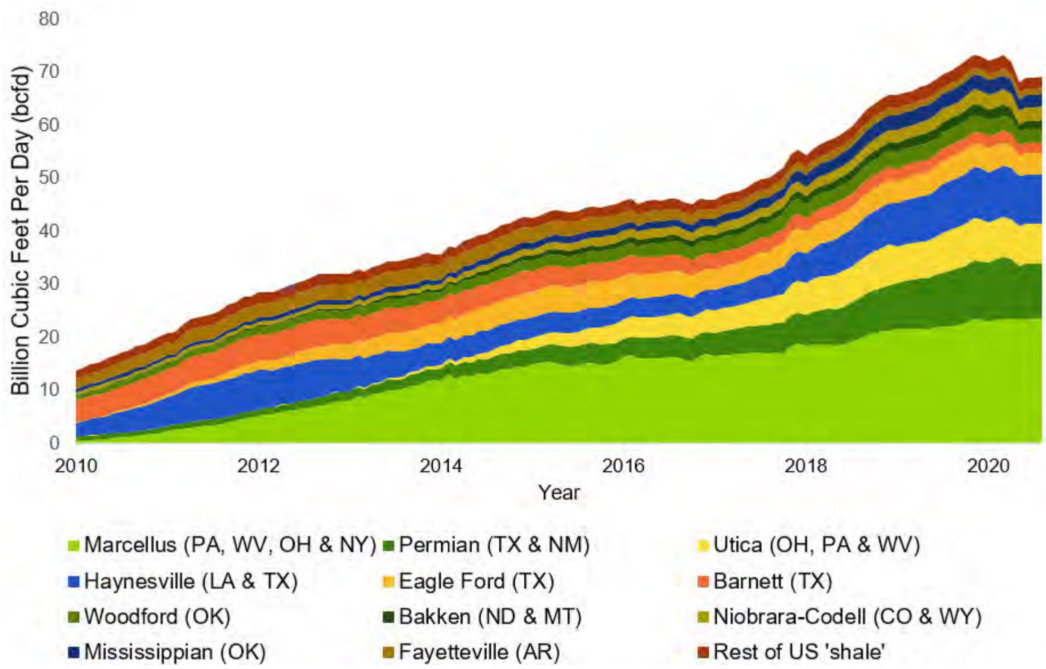
For energy system stakeholders at every level, resilience is not just a term that is currently in vogue, it is a characteristic that needs to be valued and engineered. Ensuring future energy system resilience will require careful assessments of all available solutions, maximizing the fundamental benefits of a diversity of assets. Utilities, system operators, regulators, and policymakers need new frameworks to consider resilience impacts as part of the energy system transformation, to ensure that resilience is not overlooked in the pursuit to achieve decarbonization goals.

Appendix A. The Natural Gas Value Chain

A.1 Production and Processing

Exploration and production companies explore, drill, and extract natural gas from geologic formations. In 2019, 81% of production came from shale.[66] Production from these formations has grown rapidly over the past decade, as Figure A-1 shows.

Figure A-1. US Dry Shale Gas Production, 2010-2020



Source: Guidehouse, US Energy Information Administration

Once produced and extracted, gathering pipelines transport natural gas to processing facilities where impurities are removed, resulting in pipeline-quality natural gas. Gathering systems use compressors to move gas through the midstream pipelines. Most compressors are fueled by natural gas from their own lines. This self-reliance increases resilience by allowing the movement of molecules without dependency on other fuel sources.

A.2 Transmission

From the gathering system, natural gas moves into the high-pressure transmission system for long-haul transportation to market centers. These pipelines efficiently move large amounts of natural gas thousands of miles.[54] In the US, there are approximately 3 million miles of mainline and other pipelines that connect gas production with consumption.[55] Over 30 companies in North America own and operate interstate pipelines, which the FERC regulates. Intrastate pipelines are generally owned by publicly traded entities and are regulated by the states in which they are located.

[54] American Gas Association. *How Does the Natural Gas Delivery System Work?*. Accessed October 2020.
[55] EIA. *Natural Gas Explained: Natural Gas Pipelines*. Accessed October 2020.

A.2.1 Compressor Stations

The pressure of gas in each section of the transmission system ranges from 200 psi to 1,500 psi, depending on where the pipeline operates. Compressor stations are located approximately every 50 to 60 miles along transmission pipelines to regulate pressure and keep gas moving.

A.2.2 Gas Storage

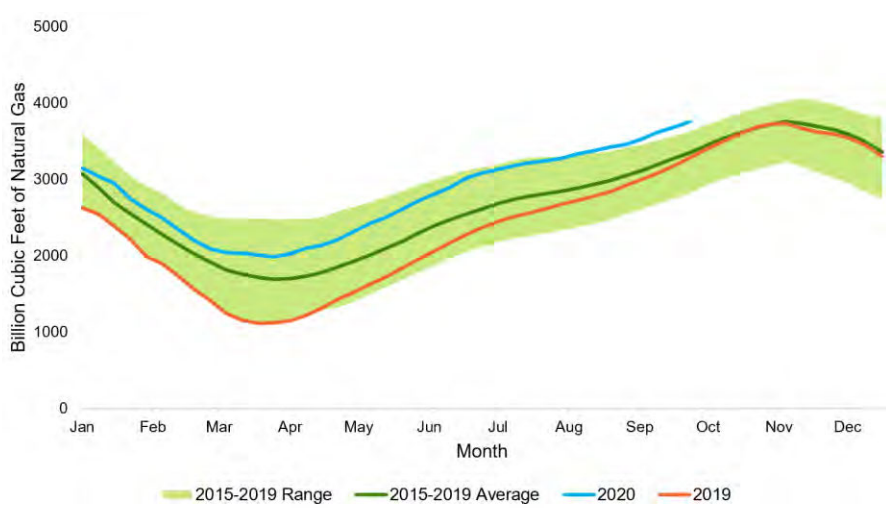
Storage capacity enables the delivery of reliable gas service to consumers and end-users throughout the year. While natural gas production remains relatively constant year-round, storage enables gas providers to adjust to daily and seasonal demand fluctuations (Figure A-2).

Storage can be owned or operated by natural gas transmission companies or LDCs. Off-system storage is not directly tied to a natural gas utility's distribution system, but that is accessible via the transmission system. Most off-system storage is underground; however, there are examples of aboveground off-system storage. Underground storage facilities can be developed from depleted gas reservoirs, aquifers, or salt caverns and are connected to one or more transmission pipelines; whereas aboveground storage is often provided through LNG or CNG.

In addition to offering storage services, some pipeline companies may provide a park and loan that enables shippers to borrow or lend gas. These services are typically used to balance daily or intraday markets. Some Pipelines also offer tariff-based delivery services called No Notice, which allows an LDC to receive gas at variable quantities throughout the day without placing nominations to the provider. These no-notice services are backed by storage and pipeline delivery assets.

In the lower 48 states, it is common for the gas system to have at least 2,000 Bcf to 3,000 Bcf of working natural gas in underground storage, as Figure A-2 shows. The entire US commercial sector consumed 3,500 Bcf in 2019. Base gas (or cushion gas) is the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of gas in the reservoir above the level of base gas. Base gas inventories remain relatively steady at approximately 4,300 Bcf throughout the year.

Figure A-2. Working Gas in Underground Storage, Lower 48 States



Source: Guidehouse, US Energy Information Administration

A.2.3 City Gate Stations

Natural gas typically passes through a city gate to move from the transmission pipeline to the pipelines under operational control of LDCs. At the city gate, the pressure is reduced from transmission to distribution levels, an odorant is added, if not already provided by the upstream pipeline, and incoming flow is measured to ensure it matches the LDC's distribution requirements. Deliveries from transmission pipelines are normally scheduled a day or more prior to delivery and include the estimated total quantities for demand in the day forward. Some transmission systems provide operators the ability to make intraday changes to nominations in attempt to sync scheduled demand with actual demand.

In addition, pipeline midstream companies and inter-connection pipelines (i.e., LDC or other midstream pipeline companies) have OBAs in place in which parties agree to specified procedures for balancing between nominated levels of service and actual quantities transferred between the two pipelines.

A.3 Distribution

After leaving the city gate, natural gas moves into distribution pipelines. Each distribution system has sections that operate at different pressures, with mechanical regulators controlling the pressure to optimize efficiency. Generally, the closer natural gas gets to a customer, the lower the pressure.

Many distribution systems also feature on-system storage. This is typically aboveground and includes small-scale LNG or CNG storage that enables the distribution company to meet short-term requirements for increased gas demand and pressure balancing needs. Such facilities enable LDCs to supplement, or shave, the amount of natural gas needed from external suppliers through on-system resources. Some distribution systems also feature underground storage.

A.3.1 Customer Delivery

As gas travels through the main lines of the distribution system, it is routed to customers through smaller service lines. Flow meters and mechanical regulators reduce the pressure to under 0.25 psi, the normal pressure for gas within a household, equivalent to less pressure than a child blowing bubbles through a straw.

The types of customers served by the system include the following:

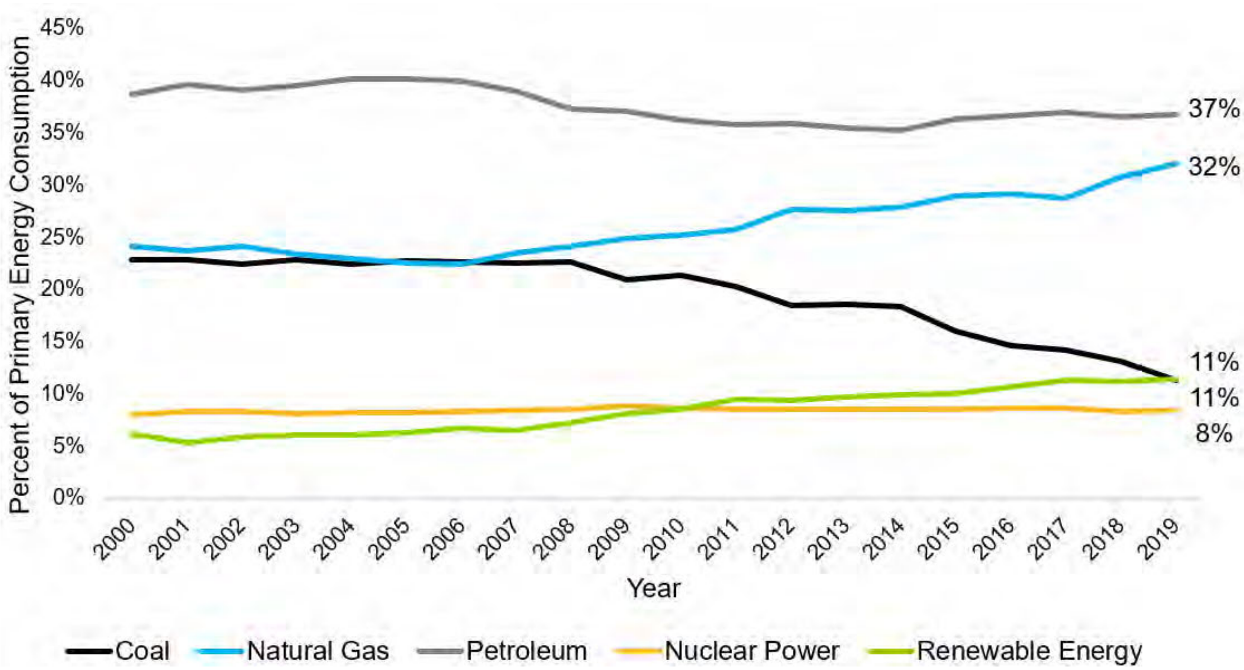
- **Interruptible vs. Firm Demand:** Interruptible customers are often large commercial or industrial customers that have selected to contract for natural gas service that can be interrupted when the delivery system is experiencing constraints. When a natural gas utility experiences a situation where gas consumption exceeds demand, such as during a peak heating day, system operators can curtail these interruptible customers while maintaining service to firm demand (or uninterruptible) customers.
- **Ratable vs Non-Ratable Flow:** Ratable flow refers to customers that will be delivered one-twenty-fourth of their nominated and scheduled daily quantity every hour—they receive the same amount of natural gas every hour of every day. Non-ratable flow refers to customers that receive uneven or varying consumption throughout the day.

Appendix B. The Current State of US Gas Consumption and Production

The US natural gas industry is larger today than ever before—gas consumption and production have grown since the 1950s and are currently at record levels. In 2019, the US consumed 31 trillion cubic feet of natural gas. Concurrently, the US produced approximately 33 trillion cubic feet of natural gas (dry production) in 2019.[56]

In 2019, natural gas accounted for 32% of US primary energy consumption.[57,58] Natural gas has been accounting for an increasing portion of the energy consumed in the US since 2000, as Figure B-1 illustrates.

Figure B-1. US Primary Energy Consumption by Source



Source: Guidehouse, US Energy Information Administration

B.1 Gas Consumption by Customer Segment

Natural gas is a significant energy source used to generate electricity in the electric sector and meet the end-use heating demands in the residential, commercial, and industrial sectors. It is also used in distributed electric power generation primarily through CHP in the industrial sector and as a transportation energy source.

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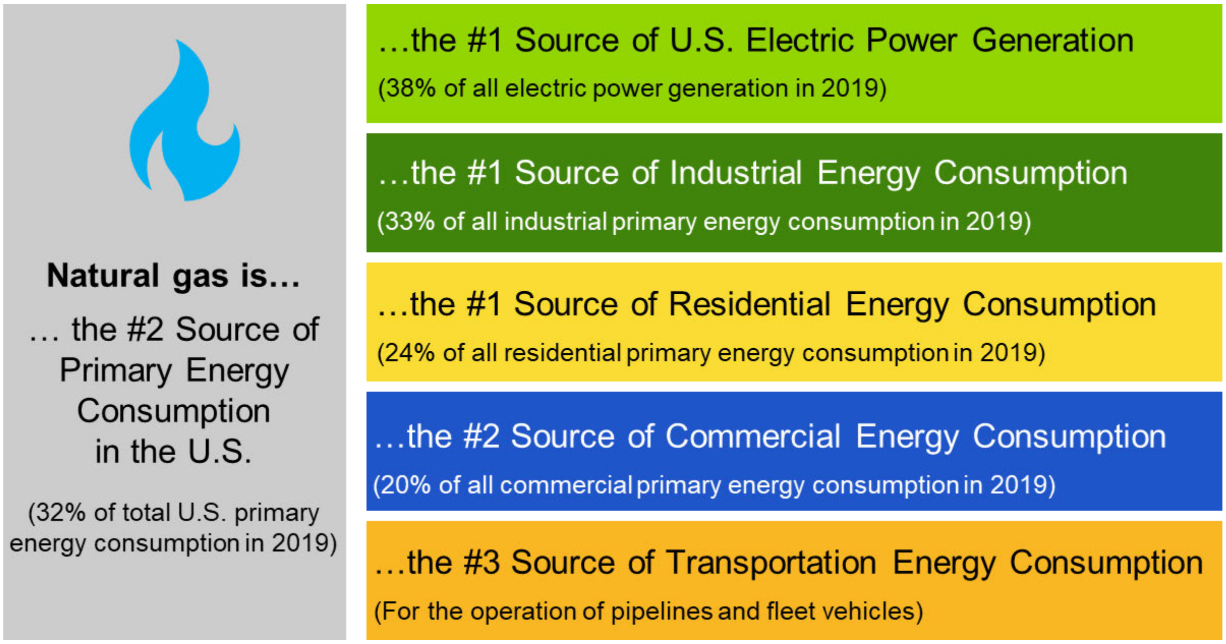
[56] EIA. 2020. *Annual Energy Outlook*.

[57] Primary energy consumption is a measure of total energy demand, covering the consumption of fossil fuels by end users like homes and businesses, the energy used to produce electricity, and losses during the transformation and distribution of energy.

[58] EIA. 2020. *Annual Energy Outlook*.

Figure B-2 illustrates the role that natural gas plays in powering each of these sectors. Natural gas supply is also detailed further throughout the remainder of this section.

Figure B-2. Natural Gas Deliveries and Consumption by Sector



Source: Guidehouse, US Energy Information Administration

B.1.1 Electric Power Generation

Growth in shale gas production has led to a decline in natural gas prices and has contributed to steady growth in the amount of electric power generated by natural gas (Figure B-3).

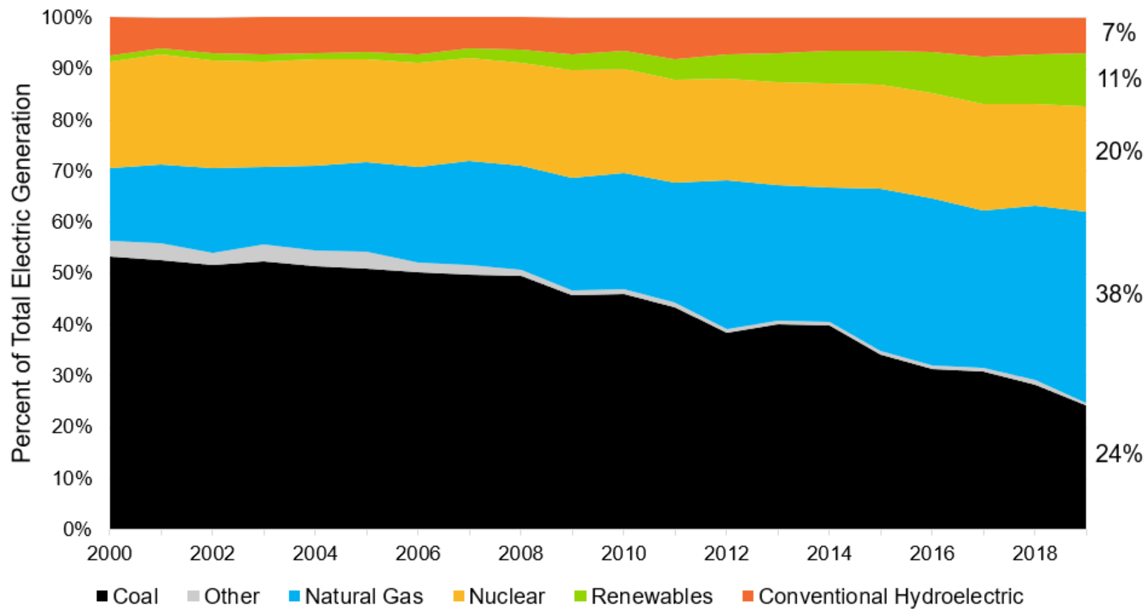
> *In 2019, 6,025 utility-scale gas generation facilities produced 38% of total US electricity, the largest share of any individual source. This is up from 5,722 gas generation facilities producing 33% of total US electricity in 2016.*[59]

The price of natural gas is a key driver behind its growth as a source of electricity production. This trend continues today, with the 2025 EIA outlook for the levelized cost of electricity of next-generation coal plants hovering around $76/MWh, and combined cycle natural gas plants around $38/MWh. This is in-line with EIA projections for non-dispatchable technologies such as onshore wind ($40/MWh) and solar PV ($33/MWh), and cheaper than projections for offshore wind ($122/MWh) and hydroelectric ($53/MWh).[60]

Grid operators find value in gas-fired electric power generation because of its flexibility as an energy resource, serving as both high capacity factor baseload and dispatchable generation. The fast ramp-up and ramp-down times of natural gas generators are especially important in regions with a large share of renewables generation where natural gas plants are often required to balance the steep increase and decrease in generation capacity.

[59] EIA. 2020. *Preliminary Monthly Electric Generator Inventory, September 2020*.
[60] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

Figure B-3. Net Electric Power Generation by Source, 2000-2019



Source: Guidehouse, US Energy Information Administration

B.1.2 Industrial

Natural gas is critical to meeting the energy needs of the industrial sector. In 2019, the industrial sector accounted for 33% of total US natural gas consumption, which in turn accounted for 33% of the industrial sector's total energy consumption.[61]

Within the industrial sector, natural gas supports a wide range of uses including building heating, a feedstock for CHP, and as a feedstock for high energy-intense processes such as the production of chemicals, fertilizer, and steel.

B.1.3 Residential

In the US residential sector, natural gas is used to heat homes and water, cook, and dry clothes. Although the use of natural gas varies by geography (as Figure B-4 illustrates), about half of the homes in the US use it for space and water heating. In 2019, the residential sector accounted for approximately 16% of total US natural gas consumption, which translates to 24% of the residential sector's total primary energy consumption.[62]

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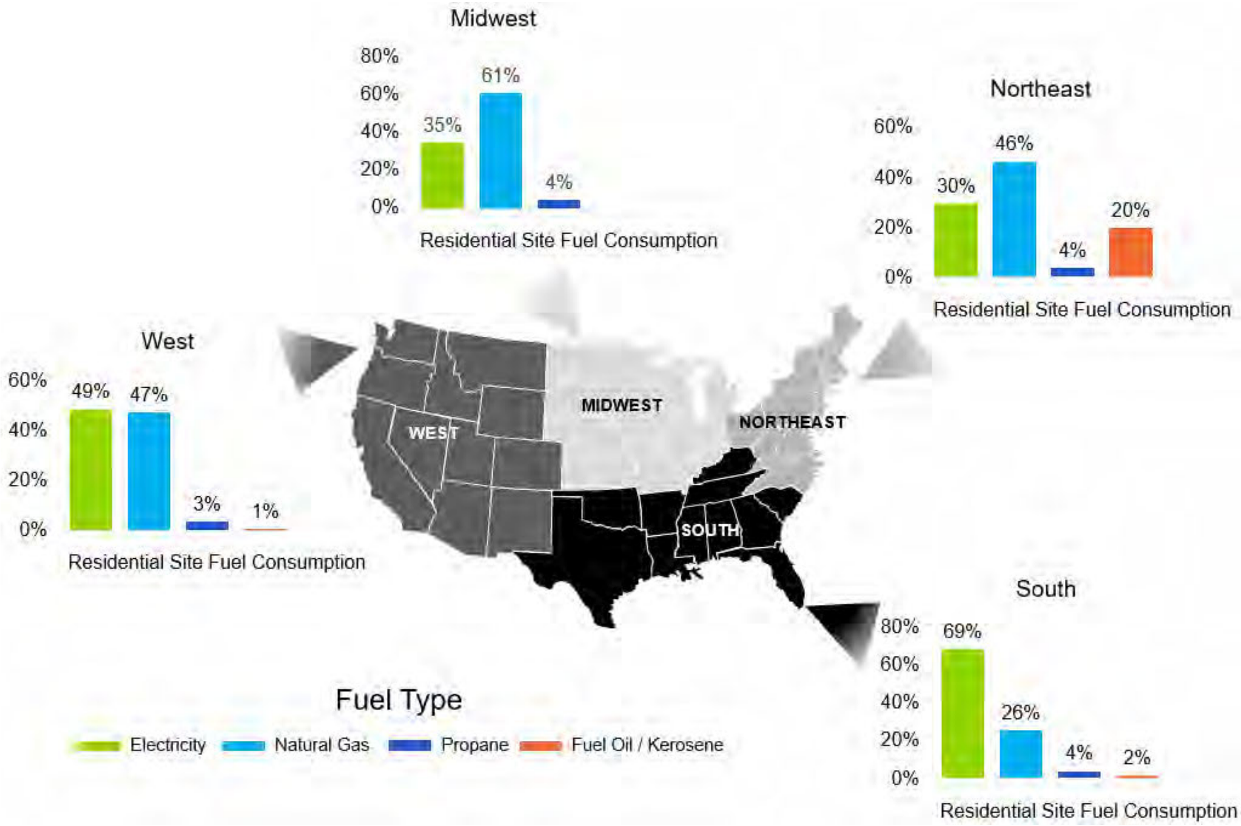
[61] EIA. Natural gas explained: Use of natural gas. Accessed September 2020.

[62] EIA. 2020. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.

Figure B-4. Natural Gas Share of Total Residential Energy Consumption, 2015



Source: Guidehouse, US Energy Information Administration

B.1.4 Commercial

In the US commercial sector, natural gas is primarily used to heat buildings and water, to operate refrigeration and HVAC equipment, to cook, dry clothes, and provide outdoor lighting and heating. In 2019, the commercial sector accounted for approximately 11% of the total US natural gas consumption, which translates to 20% of the commercial sector's total primary energy consumption.[63]

B.1.5 Transportation

Natural gas plays a niche role in the US transportation sector, accounting for only 3% of the sector's total energy needs in 2019. Within the transportation sector, natural gas is used to operate compressors to move natural gas through pipelines and as a vehicle fuel in the form of CNG and LNG.

Most vehicles that use natural gas as a fuel are government and commercial fleet vehicles. CNG medium duty vehicles have gained increasing popularity over diesel due to lower prices and clean air benefits. In 2018, there were a total of 19,151 CNG public transit busses nationwide, compared to 32,671 diesel and 13,872 hybrid busses.[64] In 2020, there are 1,677

[63] EIA. 2020. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020.*

[64] DOE. *Alternative Fuels Data Center, Transit Buses by Fuel Type*. Accessed October 2020.

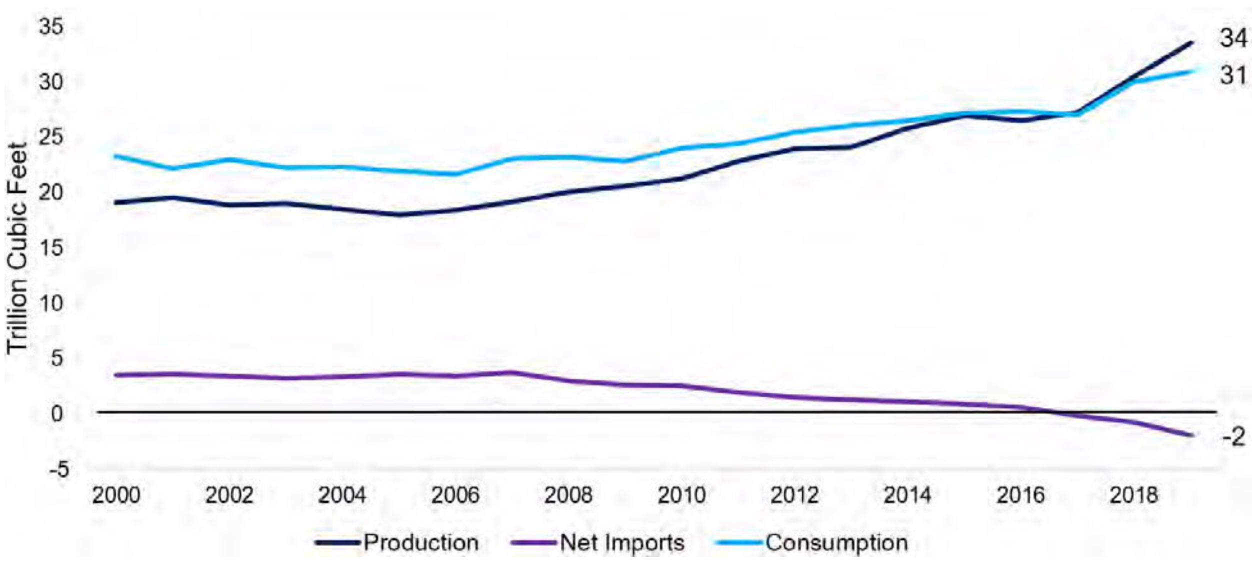
CNG and LNG refueling sites in the US compared to 29,738 EV stations. However, this infrastructure supports decarbonization of heavy and medium to light duty vehicles where EV infrastructure primarily supports light duty vehicles.[65]

B.2 US Gas Production

US natural gas production continues to grow; domestic production has exceeded consumption since 2017. The US now produces nearly all the gas it consumes, decreasing its reliance on imports from other countries. In large part due to accessible shale formations, most natural gas (97%) is produced onshore in a diversified base of over 30 states. Five states (Texas, Pennsylvania, Oklahoma, Louisiana, and Ohio) account for approximately 70% of the US total dry natural gas production.[66]

In 2019, 34 trillion cubic feet of natural gas was produced (Figure B-5).[67] Increased domestic production has contributed to a decline in prices, which has led to the significant increase in natural gas consumption across sectors, primarily in the electric power generation and industrial sectors.

Figure B-5. US Natural Gas Consumption, Dry Production, and Net Imports, 2000-2019



Source: Guidehouse, US Energy Information Administration

B.3 Low Carbon Gas Production

Since the early 2000s, US energy-related GHG emissions have been decreasing.[68] A significant driver of the emissions reduction has been a transition from higher-emissions fuels (e.g. coal) to natural gas. This transition is expected to continue, as natural gas supply is further decarbonized through the increase in low carbon gas production.

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[65] Oak Ridge National Laboratory. 2020. *Transportation Energy Data Book Edition 38, Table 6.12.*

[66] EIA. *Natural Gas Explained: Where our natural gas comes from*. Accessed October 2020.

[67] EIA. *U.S. Energy facts explained*. Accessed October 2020.

[68] EIA, *EIA Projects U.S. Energy-Related CO2 Emissions Will Remain Near Current Level Through 2050.*

Fueled by city and state commitments to decarbonize, investors are driving the capital necessary for companies to invest in the further research, development, and production of low carbon gases such as RNG, hydrogen-enriched natural gas, and hydrogen. Meanwhile, political and regulatory agencies are clearing the path for the growth of this low carbon gas development. Although low carbon gas production is nascent in the US, its growth potential provides a pathway for the natural gas industry to meet energy sector decarbonization goals. It also increases the resilience of the energy system by providing a locally sourced supply of clean energy.

B.3.1 Biogas

Biogas is produced primarily through landfill gas collection, thermal gasification, or anaerobic digestion of waste feedstocks from the sewage, agriculture, food, and forestry sectors. Biogas can be used to produce heat and electricity, or it can be further processed to remove impurities to meet the standards of conventional natural gas (defined as RNG) for distribution through the gas pipeline system, as Figure B-6 illustrates. Though most RNG produced is consumed onsite for electric power generation or heating, the American Gas Foundation found that there will be about 50 trillion Btu of RNG produced in the US for pipeline injection in 2020, a number that has grown at a compound annual growth rate (CAGR) of 30% over the past 5 years.[69]

> *The number of renewable natural gas (RNG) production facilities in North America grew by 145% from 2014 to 2019.*[70]

There are over 2,200 biogas production sites in the US. Investments into new biogas systems totaled $1 billion in 2018, a number that has been growing at a CAGR of 12%.[71] In 2019, the US produced approximately 230 billion cubic feet of biogas primarily from solid waste (83%), industrial (6%), wastewater (6.5%), and agricultural (4.5%) feedstocks.[72]

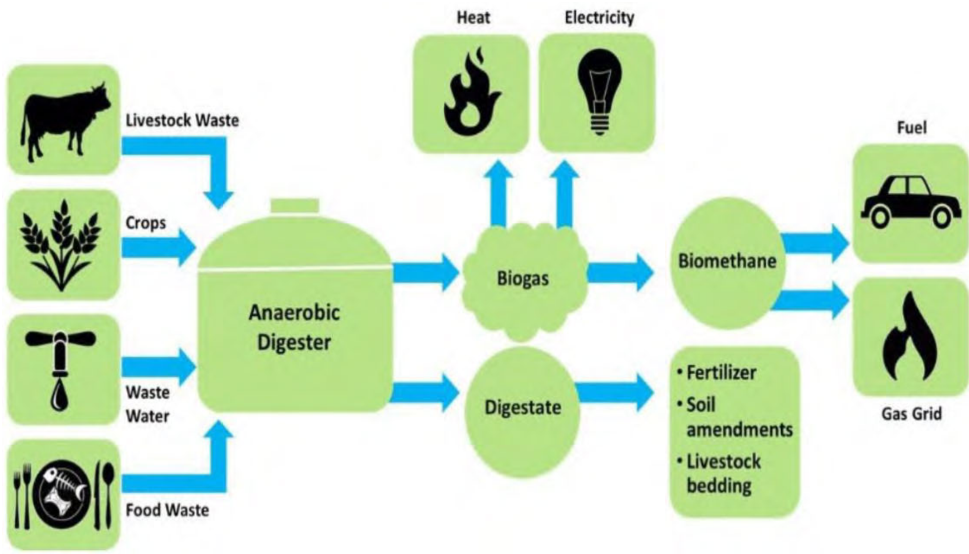
[69] American Gas Foundation. 2019. *Renewable Source of Natural Gas: Supply and Emissions Reduction Assessment.* Accessed October 2020.

[70] Coalition for Renewable Natural Gas. 2019. *Renewable Natural Gas Market Surpasses 100-Project Pinnacle in North America*. Accessed October 2020.

[71] American Biogas Council. 2019. *Why Biogas?*.

[72] Guidehouse Insights. 2020. *Renewable Natural Gas: Overview of the Current State of Biogas and Renewable Gas Markets*.

Figure B-6. Low Carbon Gas Production Through Anaerobic Digestion

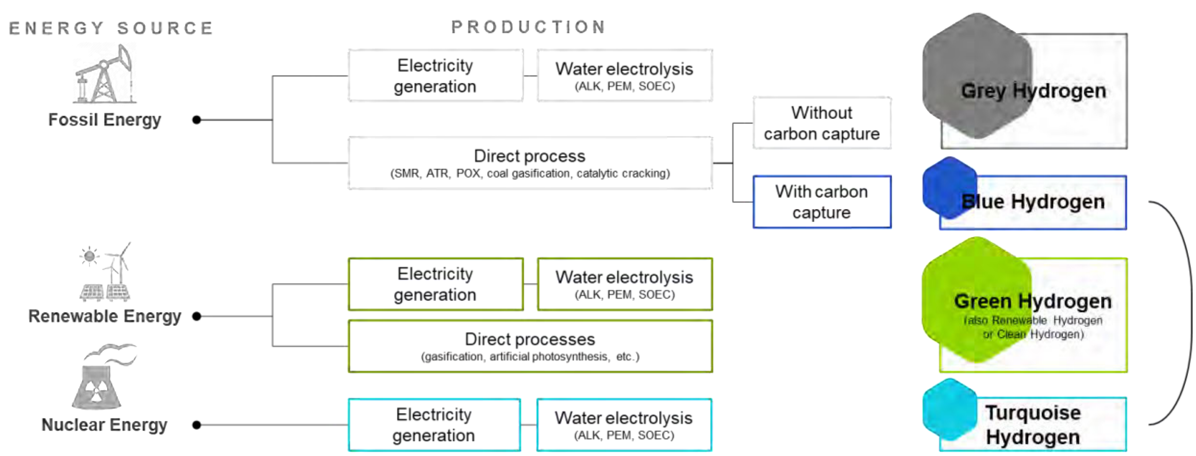


Source: Environmental and Energy Study Institute

B.3.2 Hydrogen

Hydrogen is produced through electrolysis, a splitting of water atoms into their component parts of hydrogen and oxygen. Producing hydrogen requires an input of energy, the type of energy that is used defines the carbon intensity of the process and ultimately whether it is considered low carbon. Figure B-7 describes the various types of hydrogen across a color spectrum (grey, blue, green, and turquoise hydrogen).

Figure B-7. Hydrogen Production Technologies



Source: Guidehouse

Steam methane reforming is used to form most hydrogen production. Hydrogen is often produced for use alongside its two largest consuming sectors, petroleum refining and fertilizer production. There are1,600 miles of hydrogen pipeline in the US, and most states have a large hydrogen production facility producing approximately 10 million metric tons of hydrogen annually.[73] However, a recent California Energy Commission study estimates that with market and policy action to facilitate scale-up of production capacity, California alone could produce an excess of 2,000 metric tons per day by 2030.[74]

[73] U.S. Office of Energy Efficiency & Renewable Energy. 2019. *10 Things You Might Now Know About Hydrogen and Fuel Cells*.
[74] California Energy Commission. 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibit of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1704

June 6, 2022

OPUC Natural Gas Fact-Finding Workshop #3- Modeling

UM 2178, September 14, 2021

Agenda

- Introduction
- Existing Processes and Forecasts
- Climate Protection Program Rules
- Options for Emissions Reduction
  - Demand-side Options
  - Supply-side Options
- Base Case Compliance
- Scenario Compliance

NW Natural®

Introduction to CPP Modeling

- This modeling represents a base-case of 30-years of compliance with the Climate Protection Plan and requested scenarios from Staff of the OPUC.
  - We are still waiting on final rules to be issued by the ODEQ, so it is very possible that this modeling will change after the CPP is finalized.
  - As we move forward with decarbonizing the natural gas system, our modeling will continue to evolve and change as we learn more and pursue new technologies.
  - Given compressed timeframe for the fact-finding, we could not model in the same level of detail as an IRP.

- Our next IRP will utilize final CPP rules in our long-term planning.
  - In our IRP process, we have more time to analyze, plan, and include our full risk-modeling software.
  - Our stakeholders will also have far more time to analyze and review our modeling in the IRP process.

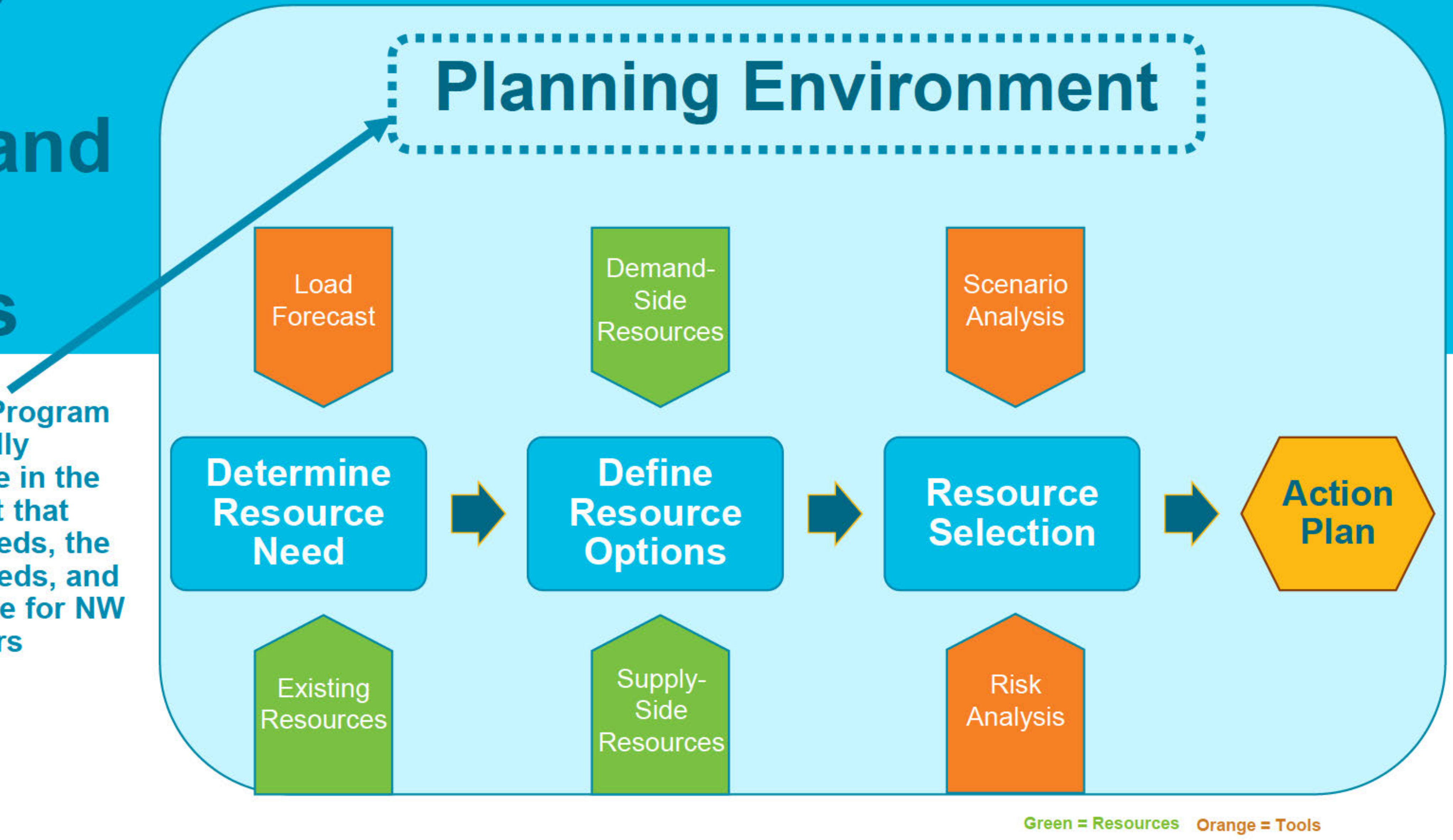
- When we look at financial impacts to customers, we focus on customer bill impacts - the actual dollars spent by customers.
  - Changes to rates do not necessarily equate to equivalent customer bill impacts.

- The modeling does not incorporate CPP assistance programs to energy burdened customers – but our regulatory tools should.

- NW Natural also continues to support a comprehensive analysis of decarbonization pathways for the electric and gas systems, including considerations of costs for all Oregonians, resource adequacy, resiliency, among other factors.
  - Exploring ways to jointly plan between electric and gas utilities should also be considered a regulatory tool we can use.

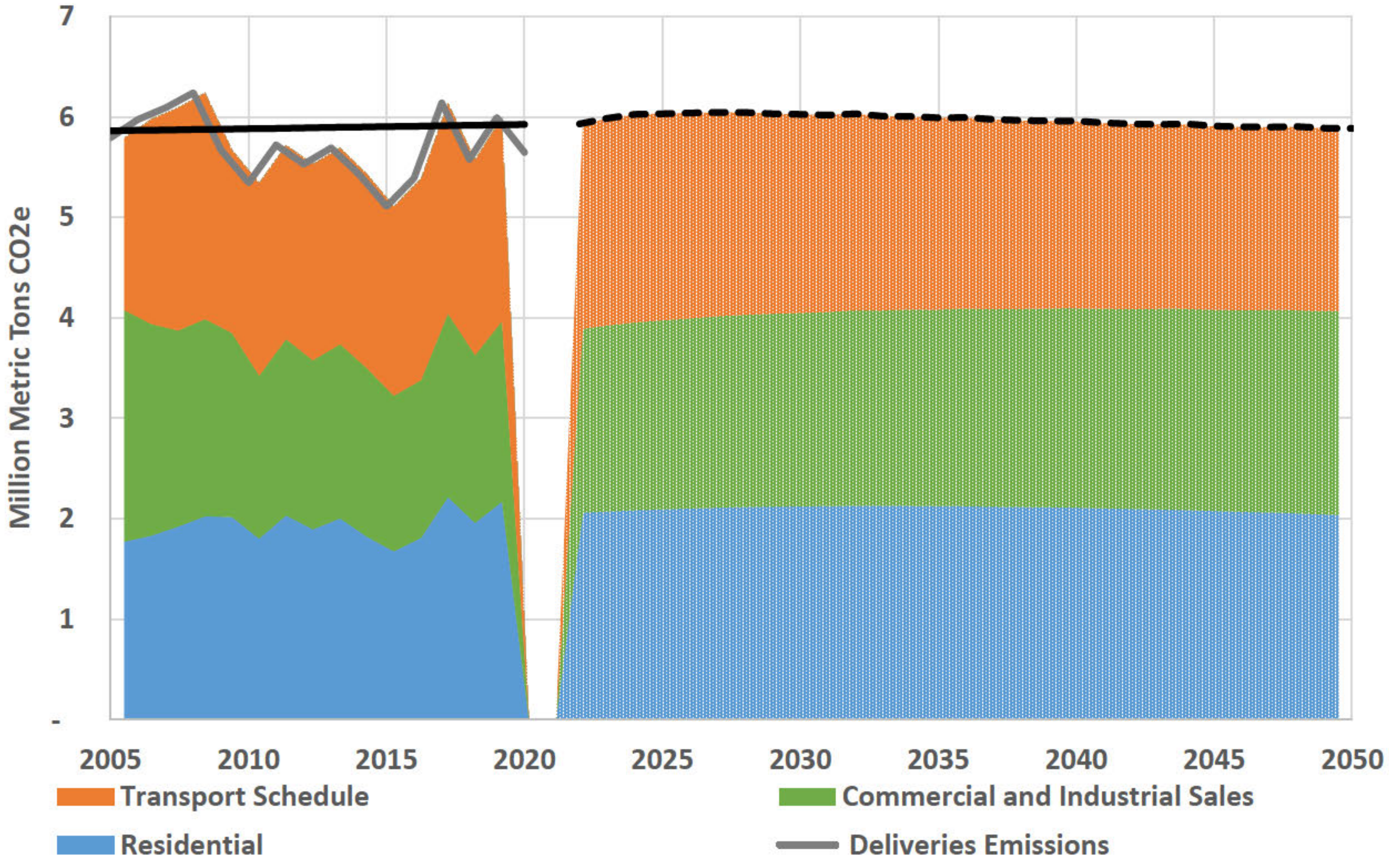
- We are happy to take questions on our presentation today, but we have limited time. Please reach out to us if you'd like more time to discuss the presentation.

Resource Planning Process and Current Forecasts



The Climate Protection Program (CPP) is a potentially transformational change in the planning environment that impacts the resource needs, the options to meet those needs, and the actions for compliance for NW Natural's customers

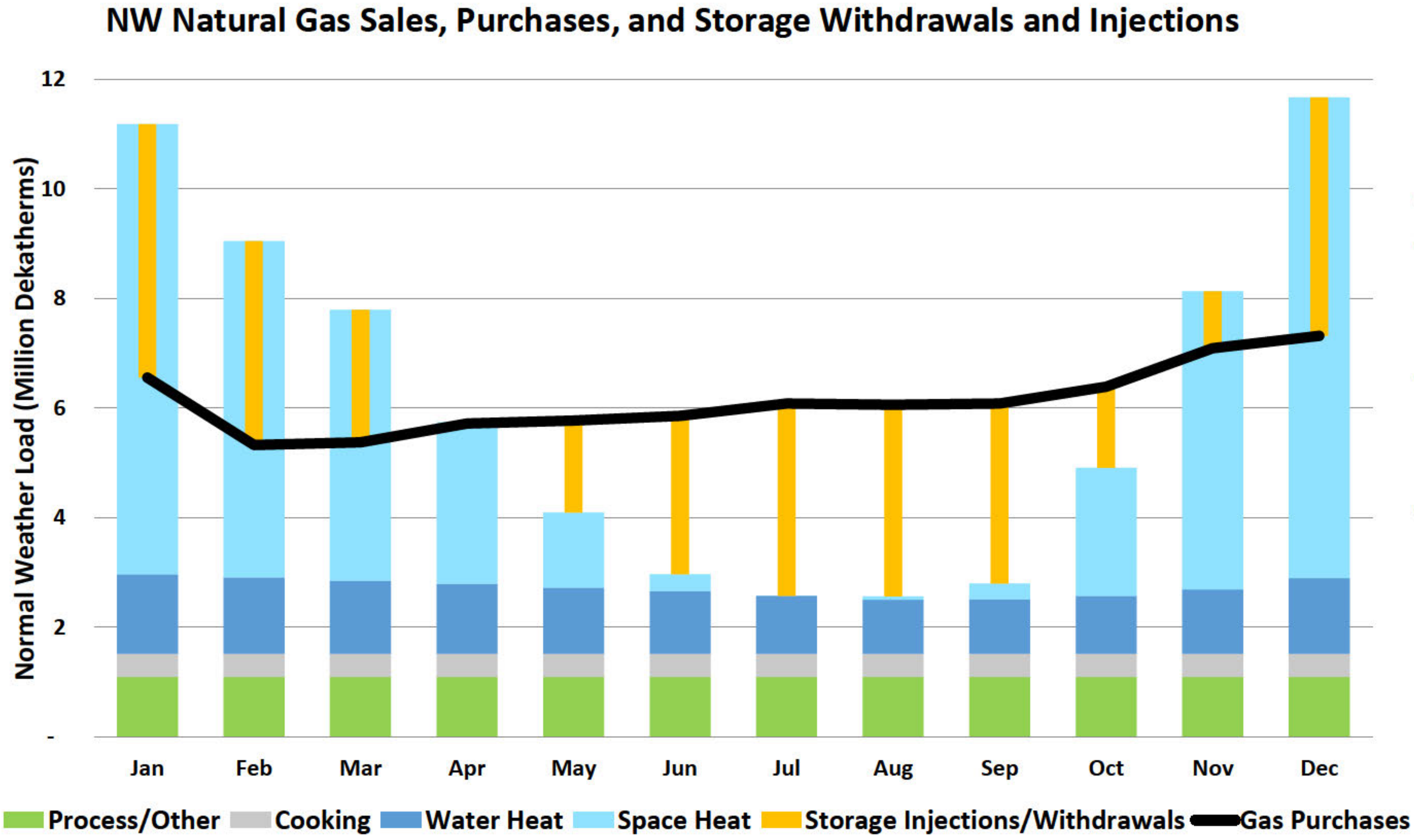
NW Natural Load History and Forecast in terms of CPP Compliance



- Includes gas delivered – but not sold – by NW Natural (i.e gas delivered on Transportation Service Schedules)
- Shows emissions as if all load was served by conventional natural gas (i.e. does not show expected decrease in emissions due to RNG and other supply-side actions)

Seasonal Load Breakdown by End Use- 2018 IRP

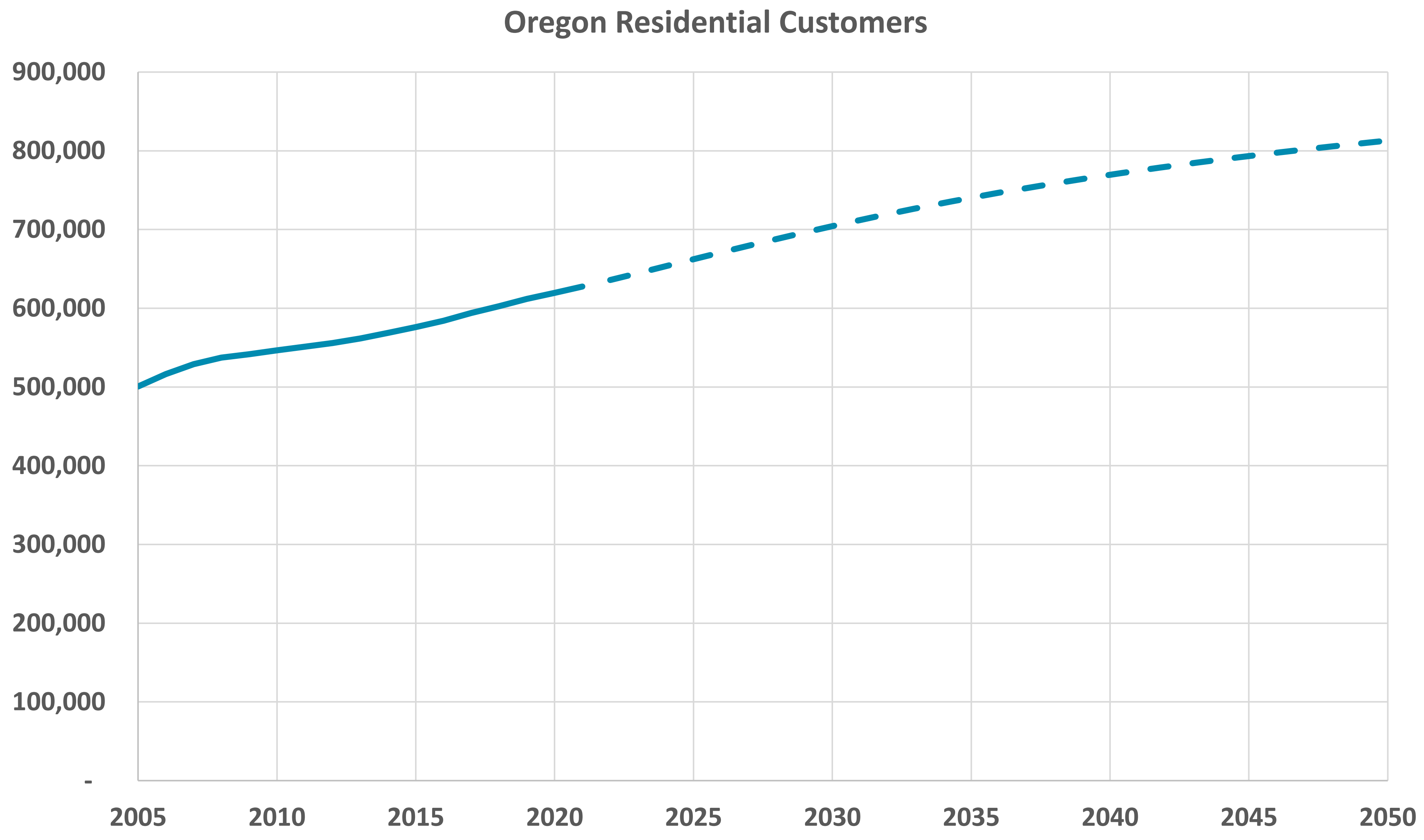
NW Natural



- Load is highly seasonal
- Seasonality needs are cost-effectively met with existing energy storage
- Peak load is roughly 3 times the average load throughout the year
- Does not include transportation schedule load

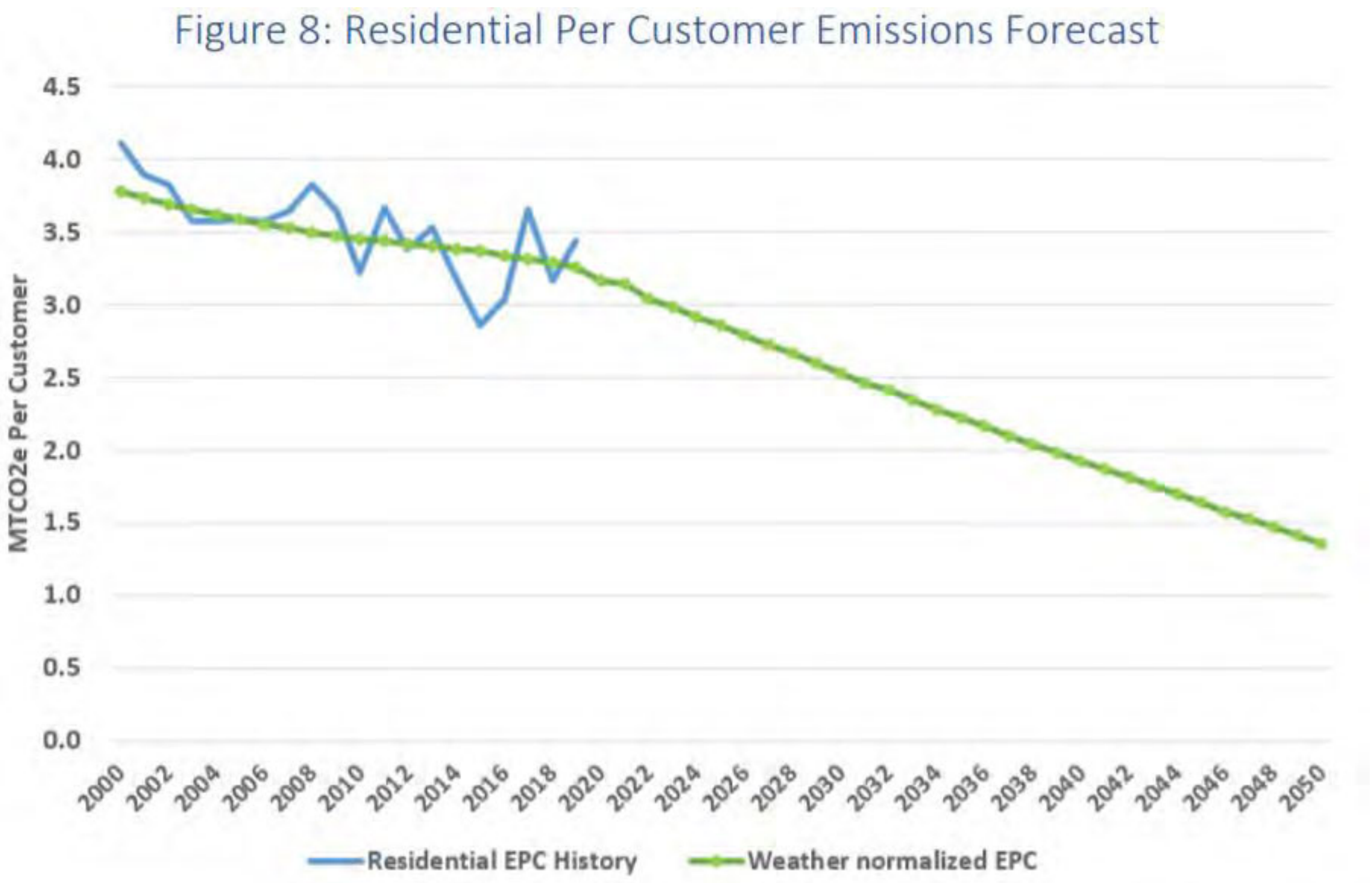
Customer Growth Expectations- IRP Update #3

NW Natural®



- **Expected Oregon Residential Customer Growth (CAGR) is 0.9% per year**

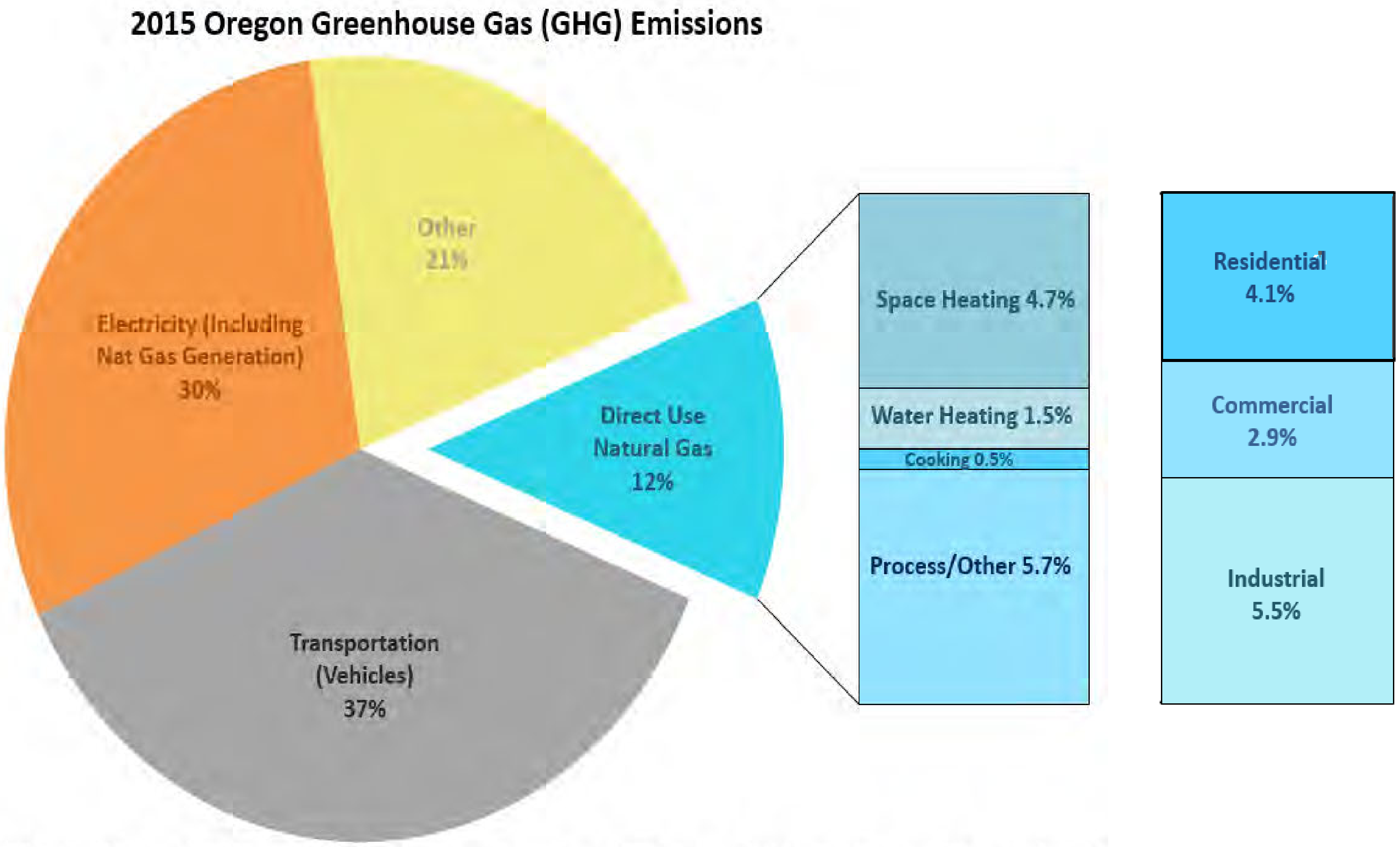
Per Customer Emissions Forecast- IRP Update #3



- Pre-CPP expectations
- Includes Washington Customer and Smart Energy
- Combined Impact of Renewable Supply Penetration and Usage Decline Expectations

Putting Emissions in Context – 2018 IRP

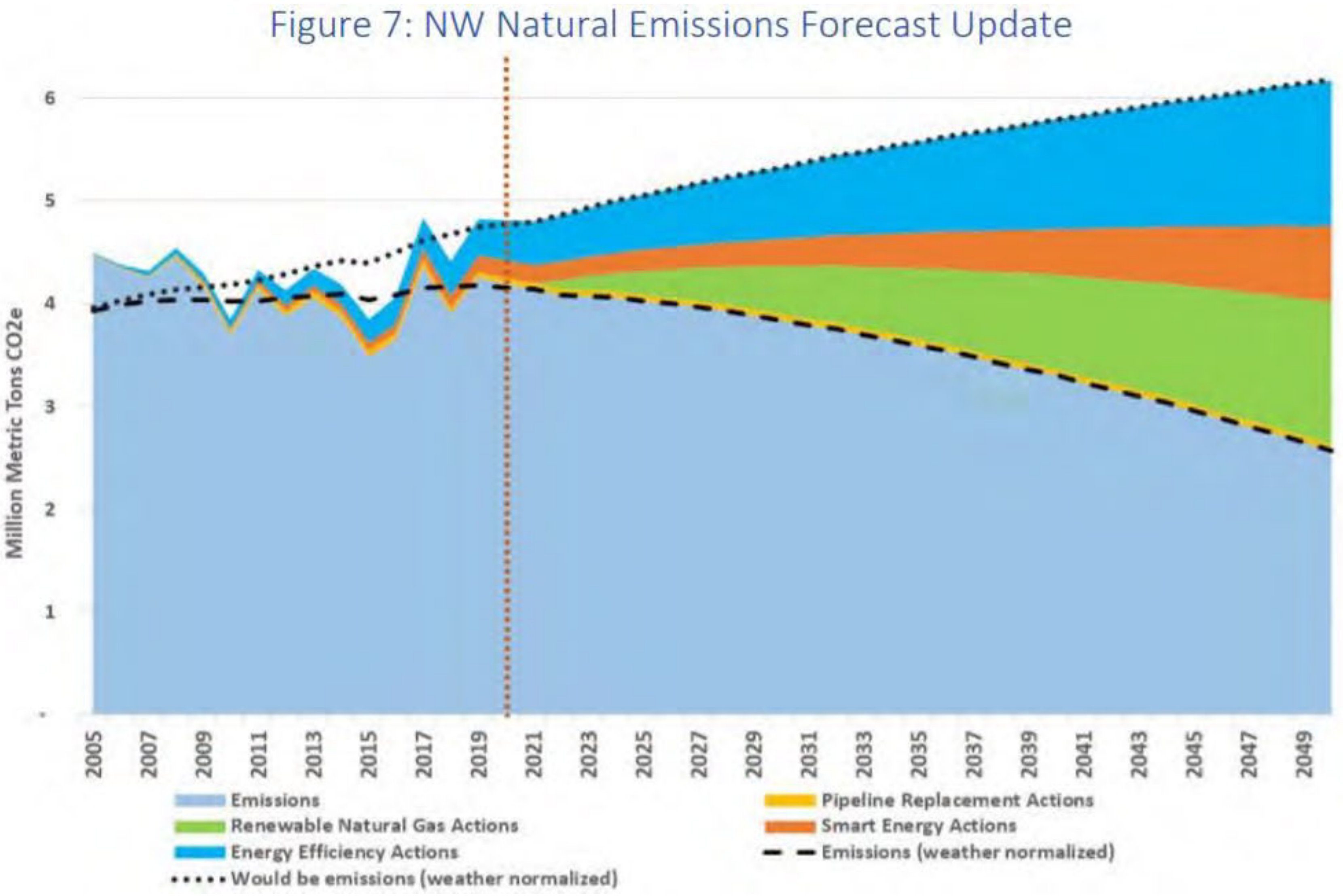
NW Natural®



Sources: (1) State of Oregon DEQ In-Boundary GHG Inventory Preliminary 2015 Figures- Residential, Commercial, and Industrial sector emissions are those that are not from electricity or natural gas use (2) Natural gas breakout: NW Natural analysis

- Roughly 70% of Oregon's space heating needs are served by direct-use natural gas
- Roughly 1/3 of direct use natural gas used in Oregon is on transportation schedules (this does not mean cars and trucks in this context)
- Roughly ½ of the natural gas associated with Oregon's energy use is used in electric generation
- Direct use gas' share of emissions have remained relatively constant over the last decade
- NW Natural represents roughly 80% of gas utility emissions covered by the CPP

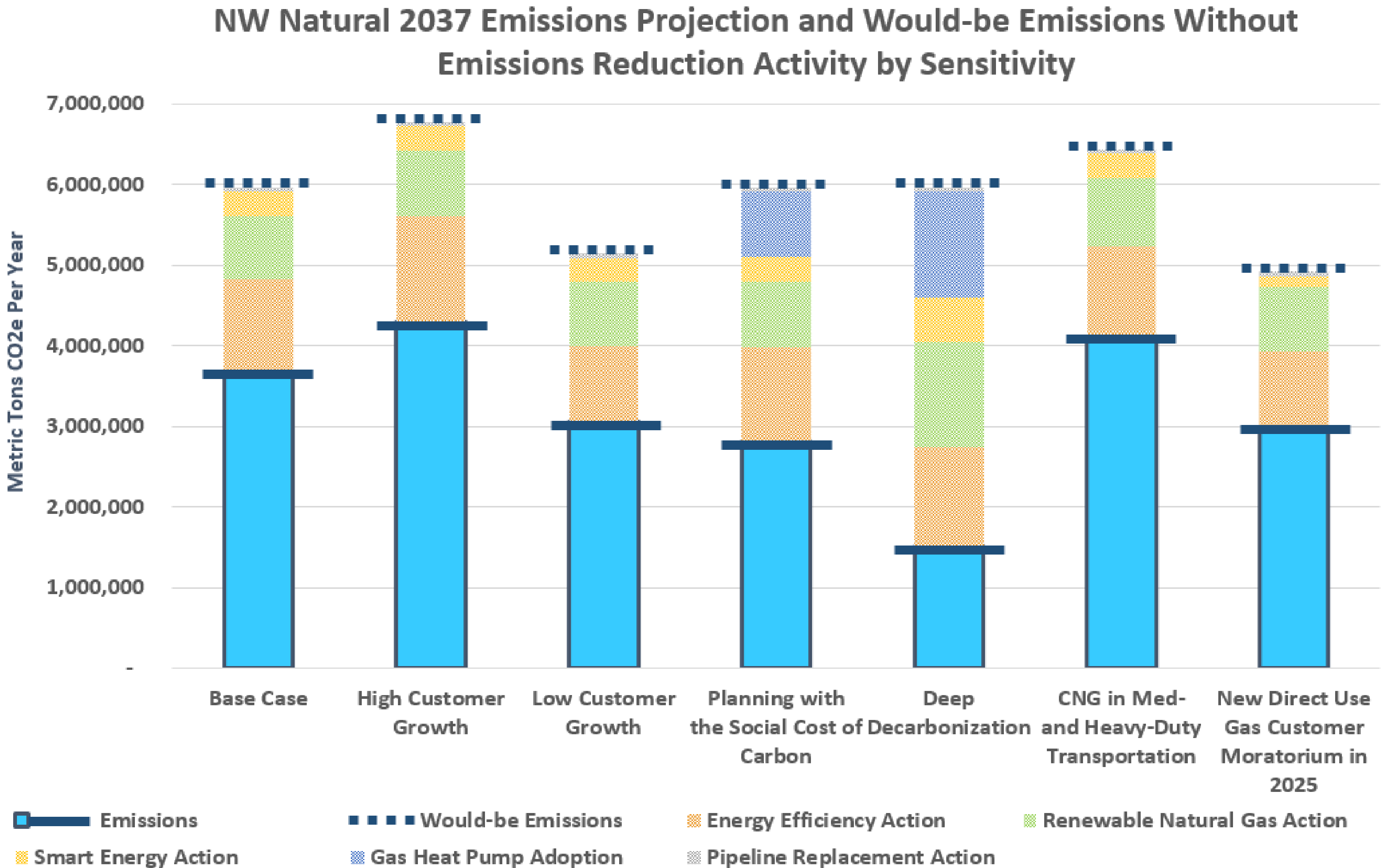
Pre-CPP Emissions Forecast- IRP Update #3



- Shows Emissions from Sales Customers Only
- Includes NW Natural's Washington Service Territory
- Includes Smart Energy Program
- Overall Emissions Trajectory has been flat since 2005 and is expected to fall even with the CPP Program

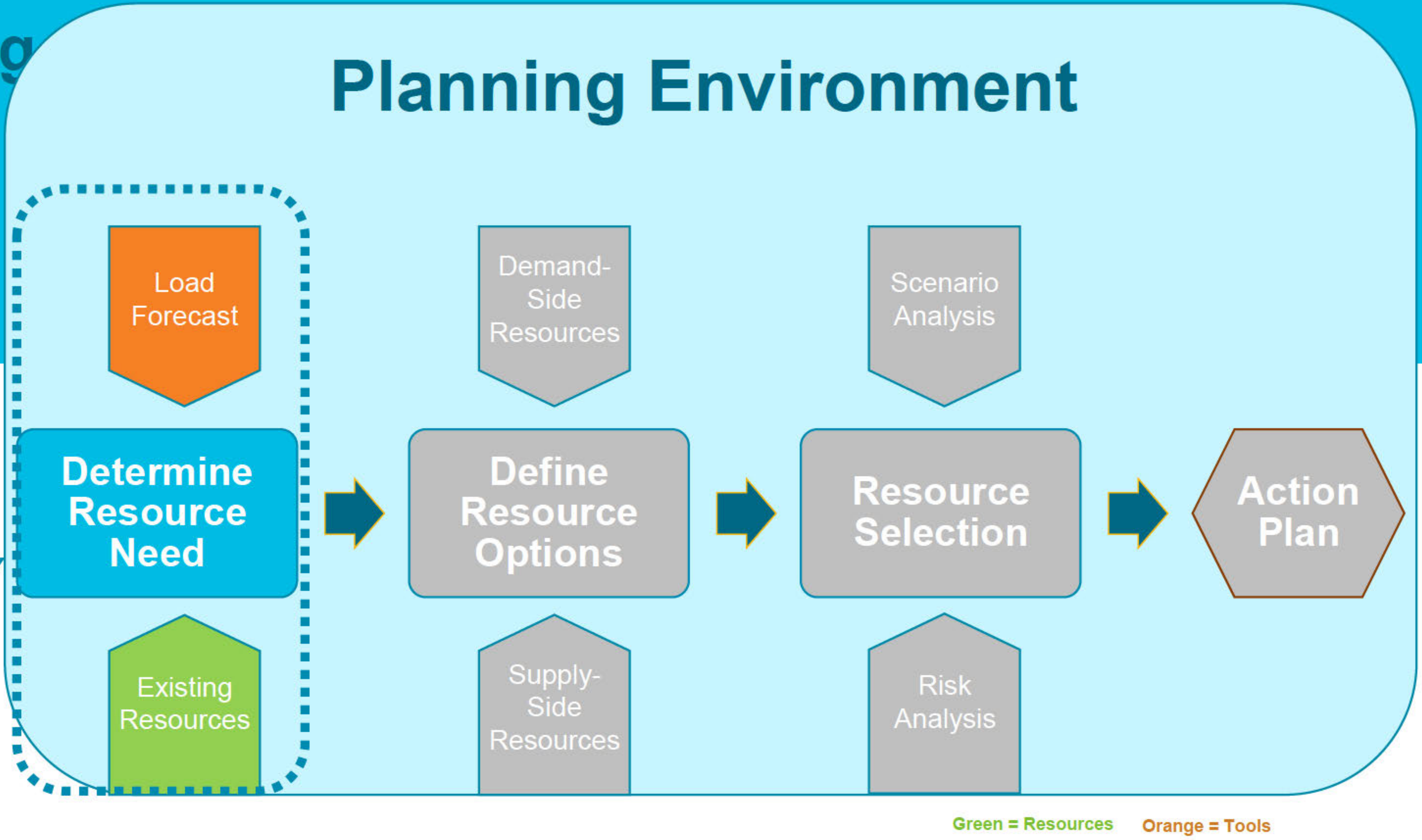
Scenarios Completed in 2018 IRP

NW Natural



- **Environmental policy uncertainty was a key driver of analysis in the last IRP**
- **Implementing the CPP is likely to be the primary driver of resource decisions in the upcoming IRP**

Understanding NW Natural's CPP Obligations



Given the draft CPP rules, the first step is determining what would be required to comply with the program

Climate Protection Program Overview

NW Natural®

- Cap and reduce program
- Covered entities include: fuels for transportation (e.g. cars and trucks), natural gas utilities, and large industrial emissions
- LDCs are responsible for emissions from all customers, excluding a few large stationary sources, but including transport customers
- Cap trajectory and emission reduction limits. LDC annual compliance instrument distribution is written into the rules:
  - 2022: 5,931,657 compliance instruments
  - 2035: 3,262,412 compliance instruments (55% reduction)
  - 2050: 1,186,331 compliance instruments (80% reduction)
- Banking and trading of compliance instruments is allowed

CPP Status and Timeline

August 5: Complete draft rule language published

October 4: Public comment deadline

December 2021: EQC meeting to consider proposed rules

January 2022-December 2024: First compliance period

November 15, 2025: First compliance demonstration

Compliance Mechanisms

Included in the draft rule language:

- Reduced consumption/ energy efficiency
- RNG
- Community Climate Investments (CCI)

More clarity needed in rules:

- Smart Energy program
- Hydrogen
- Carbon capture sequestration

Community Climate Investment (CCI) Provisions

NW Natural®

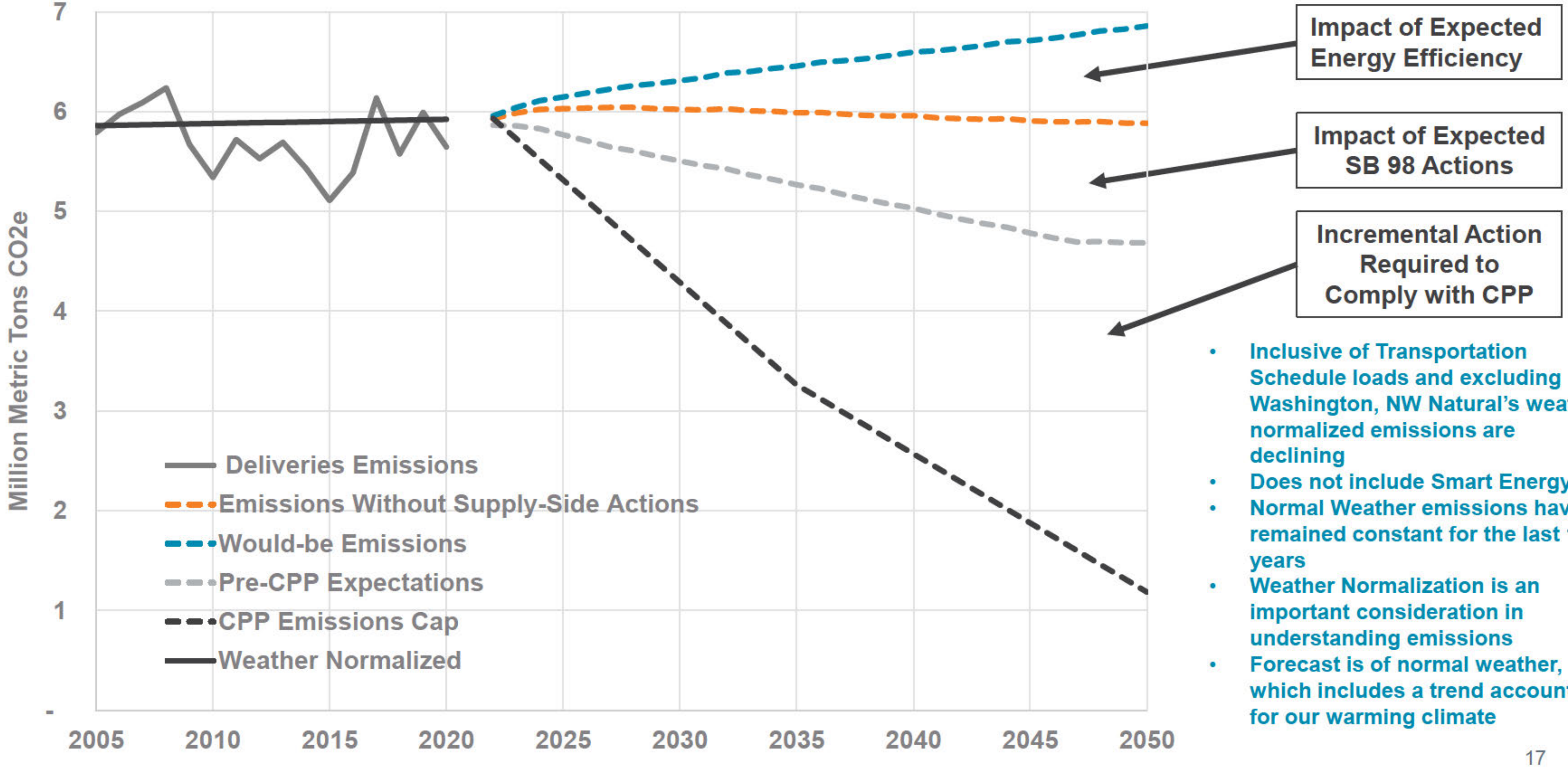
Price is fixed in the rule with a starting price of $81 per ton of CO_2e

Paying this price provides covered party with a credit for one metric ton of emissions to deduct from their emissions report

Allowable usage of CCI Credits to demonstrate compliance is limited in the rule language:

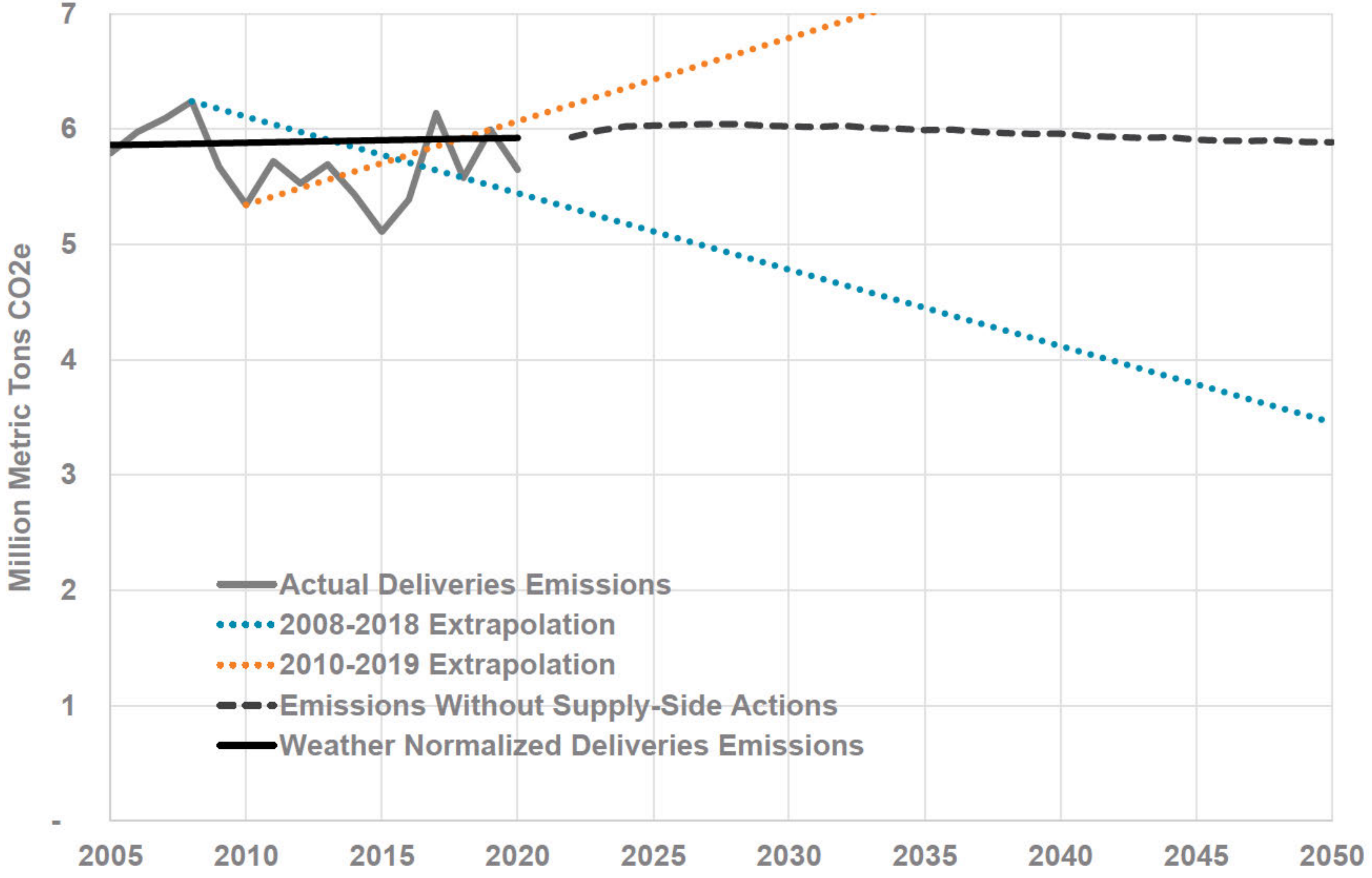
- Compliance period 1 (2022-2024): 10% of Emissions
- Compliance period 2 (2025-2027): 15% of Emissions
- All subsequent compliance periods(2028-2050): 20% of Emissions

NW Natural's CPP Compliance Needs



- Inclusive of Transportation Schedule loads and excluding Washington, NW Natural's weather normalized emissions are declining
- Does not include Smart Energy
- Normal Weather emissions have remained constant for the last 15 years
- Weather Normalization is an important consideration in understanding emissions
- Forecast is of normal weather, which includes a trend accounting for our warming climate

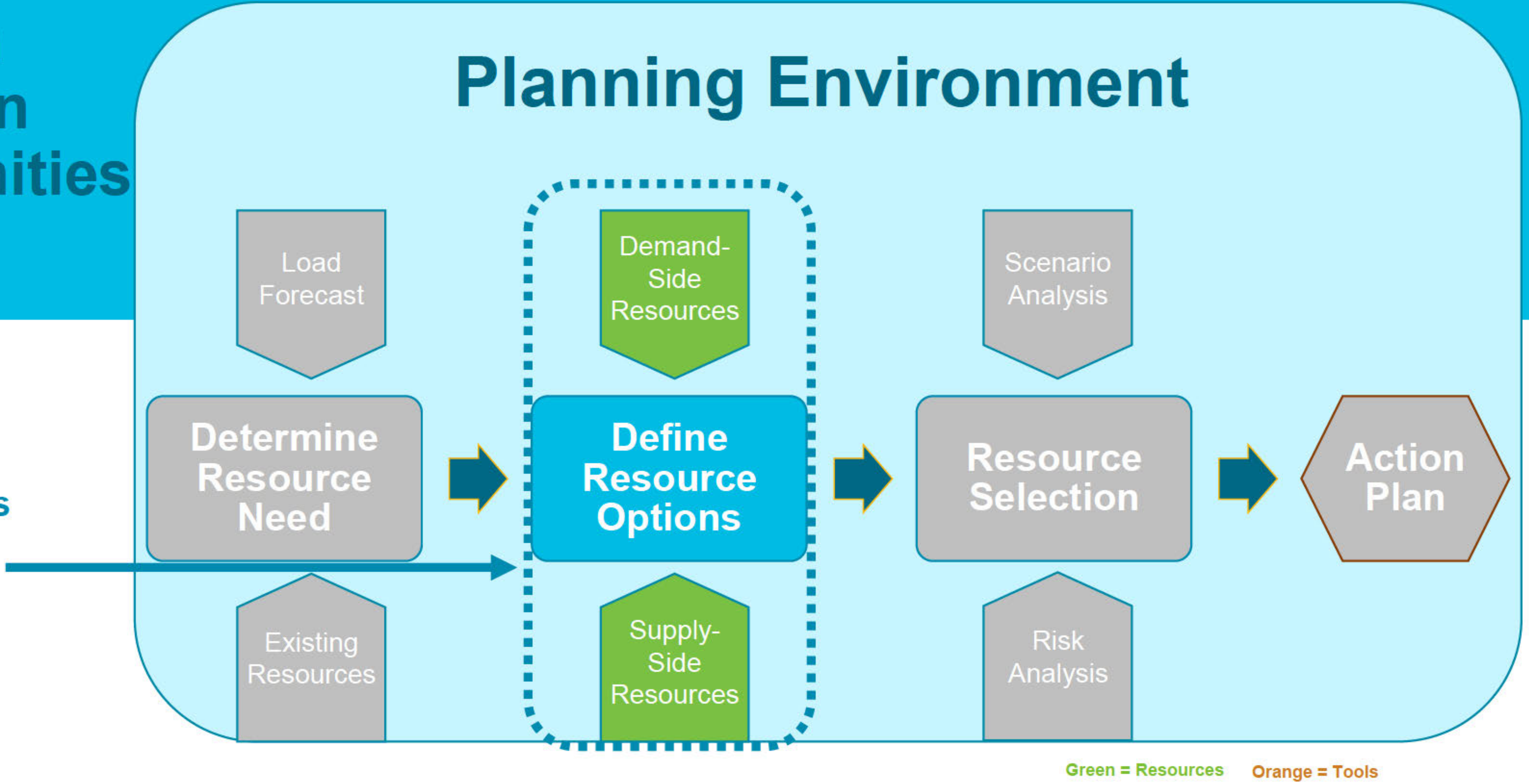
Weather Normalizing Matters



- Past usage and emissions are "noisy," and will be in the future
- Differences in weather from year to year drive this volatility
- Forecasts are shown for normal weather
- Extrapolations of non-normal weatherized data can be misleading
- NW Natural models weather that adjusts for climate change

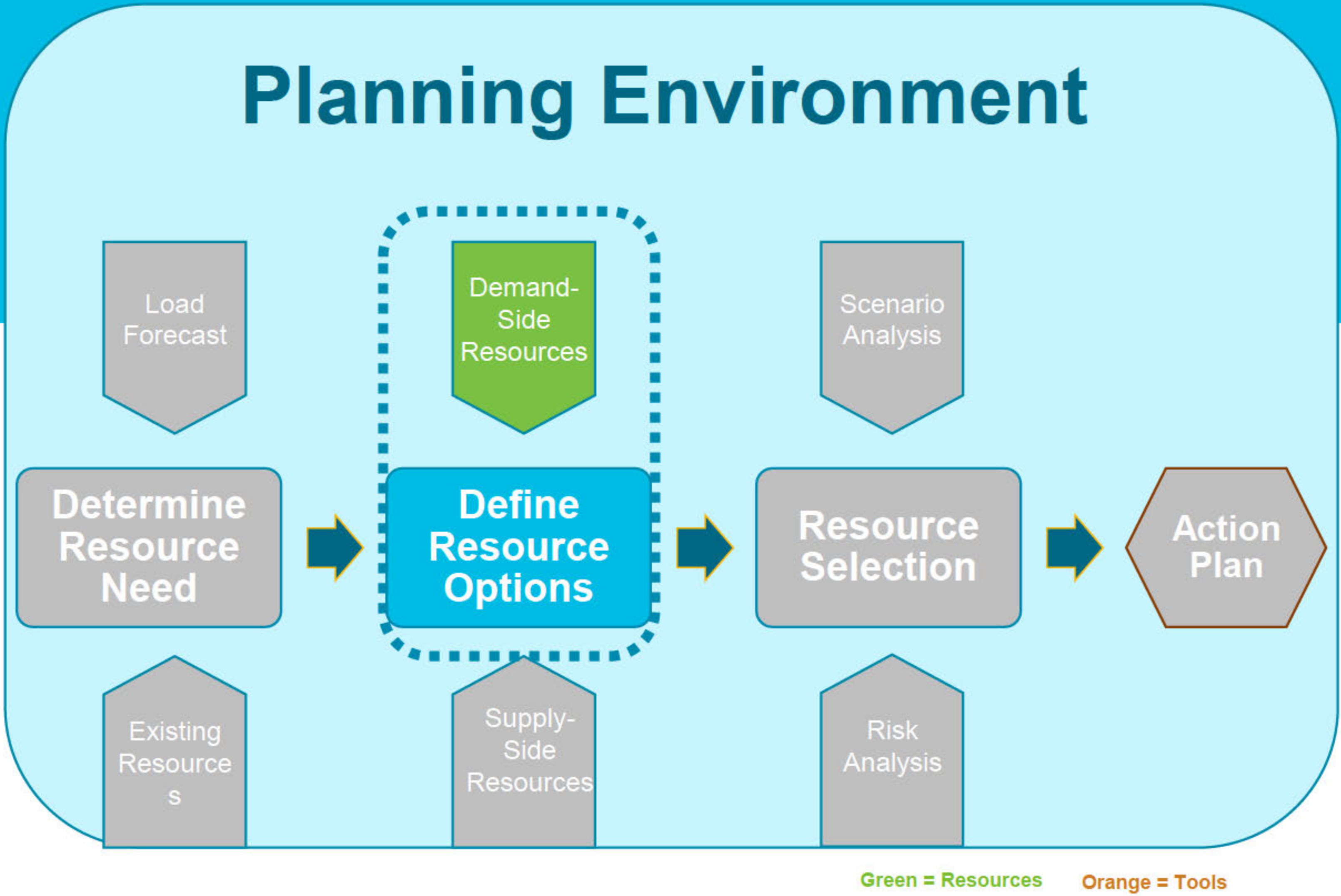
Emission Reduction Opportunities

What emissions reduction options are available?



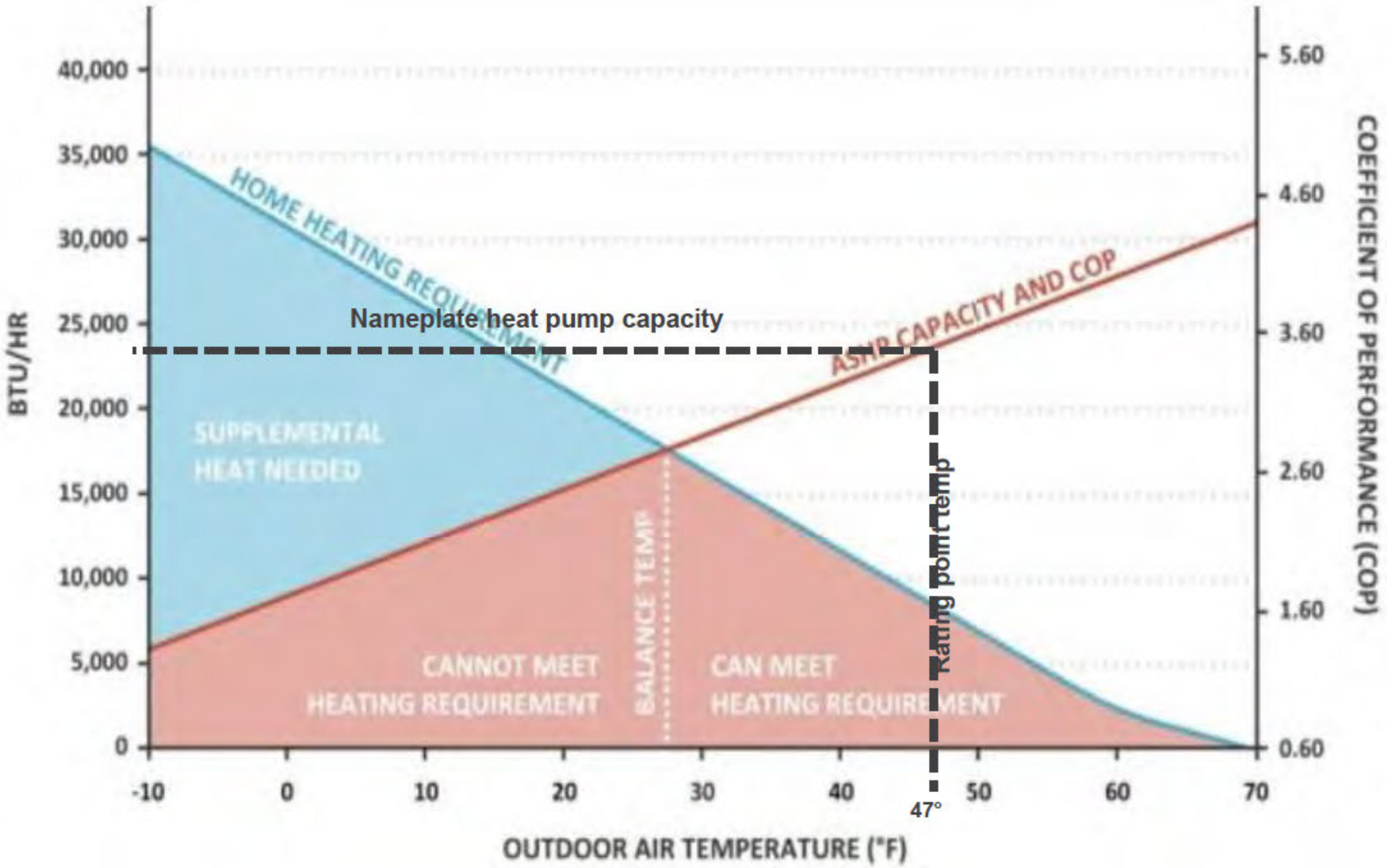
Reducing Usage-
Incremental Demand-Side Emissions Reduction Options

- Additional Funding for Existing Programs
- Industrial Decarbonization
- Dual-Fuel Heating System (Electric Heat Pump with Natural Gas Furnace Backup)
- Residential and Commercial Natural Gas-Powered Heat Pumps
- Commercial Scale Carbon Capture and Utilization



Dual-Fuel Heat Pumps-

Electric heat pump with direct use natural gas backup furnace for peak periods



- Electric heat pumps are efficient, but efficiencies decline as temperature decreases
- To maximize annual efficiency and maintain comfort electric heat pumps almost always have a backup system for cold temperatures – particularly ducted systems which are dominant in single-family homes
- An electric resistance furnace is the most common cold weather backup if a gas furnace is not used
- A system with electric resistance backup is inefficient during cold periods, which contributes large peaks to utility loads and is expensive for customers

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Dual-Fuel Heat Pumps

Benefits:

- Helps energy system resource adequacy
  - Dual-fuel systems serve as demand response for the electric grid
- Allows existing seasonal storage infrastructure to serve peak needs in a region that is capacity constrained
- Are lower cost for customers to run, particularly during cold months
- Avoids use of inefficient electric resistance heating

Challenges:

- Regulatory structure may need modification to make the setup work for customers, installers, and utilities
- Current market structure does not value capacity services across the gas and electric grids
- Incentives to homeowners/business owners and HVAC contractors may need to be reconsidered
- Reduces gas usage within a home by roughly 80% in our climate

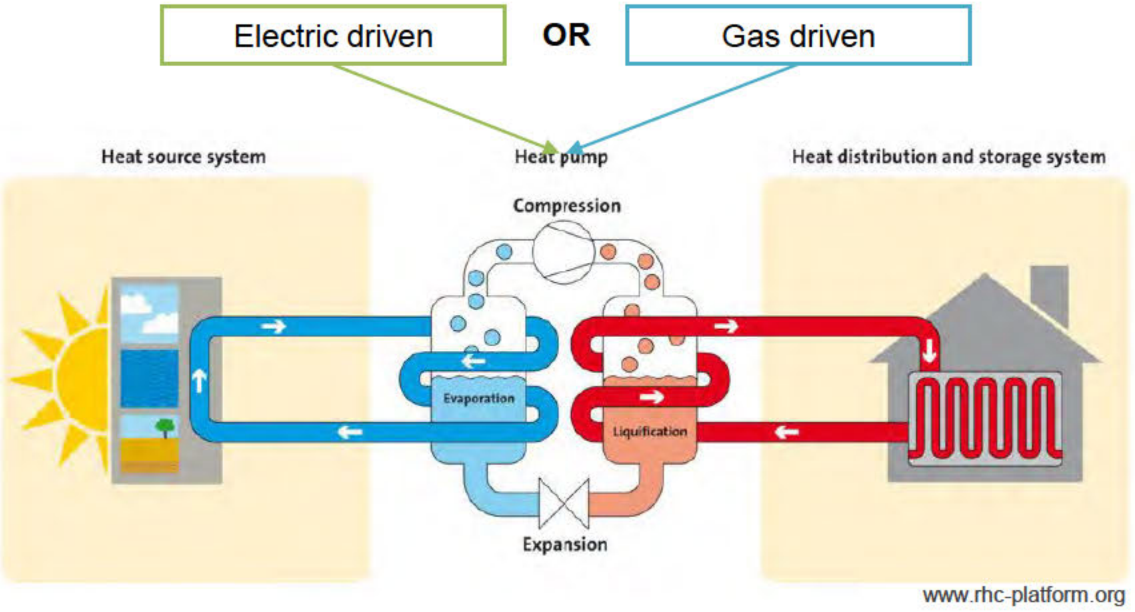
Gas Heat Pumps – GHPs

Heat Pump: Device that moves heat from one location to another; amplifying it in the process

- Many operate reversibly, providing cooling as well

Gas-driven Heat Pump (GHP*): Instead of electricity, GHPs use heat to drive the process

- Based on several technologies
- Driven by gaseous fuels including natural gas, propane, as well as blends using RNG and/or Hydrogen
- Efficient cooling feasible but not always economical
- Many use low-global warming potential refrigerants



*Or "Thermal Heat Pump" (THP)

Performance: Exceeding 100% Efficiency

Demonstration Highlights:

Residential

Water Heater (>1.20 UEF)
- **54% energy savings**[1]

Space and Water Heating/“Combi” (>140% AFUE)
- **45% energy savings**, including operation at -30ºF w/o backup heat[2]

Commercial

Hot Water/Boiler (>130% TE)
- **53% therm savings** (hot water) *and* 14% kwh savings w/A/C[3]

Internal combustion engine driven VRF (>1.50 $COP_{heating}$ >1.40 $COP_{cooling}$)
- Successful operation in both warm and cold climates[4]

Rooftop Unit (>1.30 $COP_{heating}$ @ 47ºF)
- Cold-climate testing indicates only 5% capacity reduction at 5ºF[4]

For more information: 1) Glanville, P.et al. (2020) Integrated Gas-fired Heat Pump Water Heaters for Homes: Results of Field Demonstrations and System Modeling, ASHRAE Transactions; Vol. 126 325-332.; 2) Glanville, P. et al. (2019) Demonstration and Simulation of Gas Heat Pump-Driven Residential Combination Space and Water Heating System Performance, ASHRAE Transactions; Vol. 125 264-272.; 3) Glanville, P. Innovative Applications of Thermal Heat Pumps in Multifamily Buildings and Restaurants, Presented at the ACEEE 2020 Hot Water Forum.; 4) GTI & Brio, Gas Heat Pump Technology and Market Roadmap, 2019.

North American GHP Collaborative

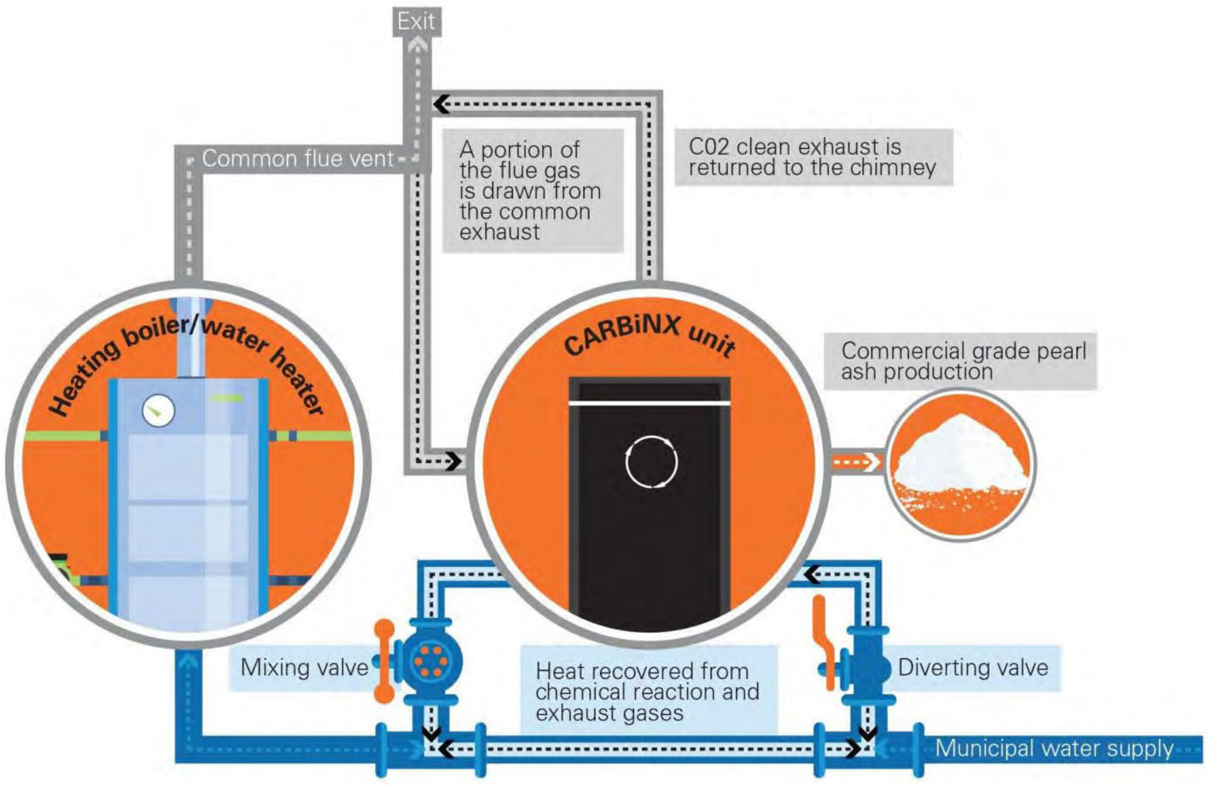
…developing and implementing activities to accelerate adoption of gas heat pump technologies

- Working with manufacturers to develop **product launch strategies**
- Conducting **market research** to inform supply chain business decisions and utility market interventions
- Adopting joint **product specifications** to ensure customer satisfaction and product performance
- Supporting **supply chain education** to prepare the market
- Offering **aligned incentives** on qualified products to drive adoption
- Working with standards-setting organizations to incorporate GHPs into **codes and standards**

Representing >30% of US and Canadian households that use gas

Carbon Capture and Utilization

- Identified technology out of Canada- provides heat recovery and carbon capture, converted to soap or fertilizer
- CleanO2 produces CARBiN-X - ideal for boilers using 240k – 1.5 million Btu/hr
- Capture rates:
  - Current: 20%
  - 2022 V4 anticipated to capture 40%
  - 2028 planning for a 100% capture model that will be commercially available in 2030
- 2021-2022 NWN piloting 3 units, modeled after peer utility pilots



Key Demand-Side Assumptions

NW Natural®

- Cost and savings of high ramp/high CO2 cost sensitivity from Energy Trust of Oregon analysis applied in all scenarios
- History and cost trajectory of large commercial and industrial energy efficiency on sales schedules applied to transport schedule loads
- Starting in 2025 30% of HVAC systems installed (both in new construction and replacement on burnout) are dual-fuel systems
- Starting in 2025 25% of HVAC and water heating systems installed (both in new construction and replacement on burnout) are natural gas heat pumps

Incremental Demand-Side Measure Costs	Incentive	Total Cost to Utility
Residential Hybrid Heating Incremental Incentive (2020$/System Install)	$1,200	$1,600
Residential Hybrid Heating Share of Incentive paid by non-CCI funds (%)	25%	$400
Residential Gas Heat Pump Incentive (2020$/System Install)	$3,000	$4,000
Residential Gas Heat Pump Water Heater Incentive (2020$/System Install)	$1,200	$1,600
Commercial Hybrid Heating Incremental Incentive (2020$/System Install)	$3,000	$4,000
Commercial Hybrid Heating Share of Incentive paid by non-CCI funds (%)	25%	$1,000
Commercial Gas Heat Pump Incentive (2020$/System Install)	$10,000	$13,333
First Year High Ramp Incremental Cost (2020$/1st year therm saved)		$5.06
First Year Transport Load Savings Cost (2020$/1st year therm saved)		$1.79

Decarbonizing Gas

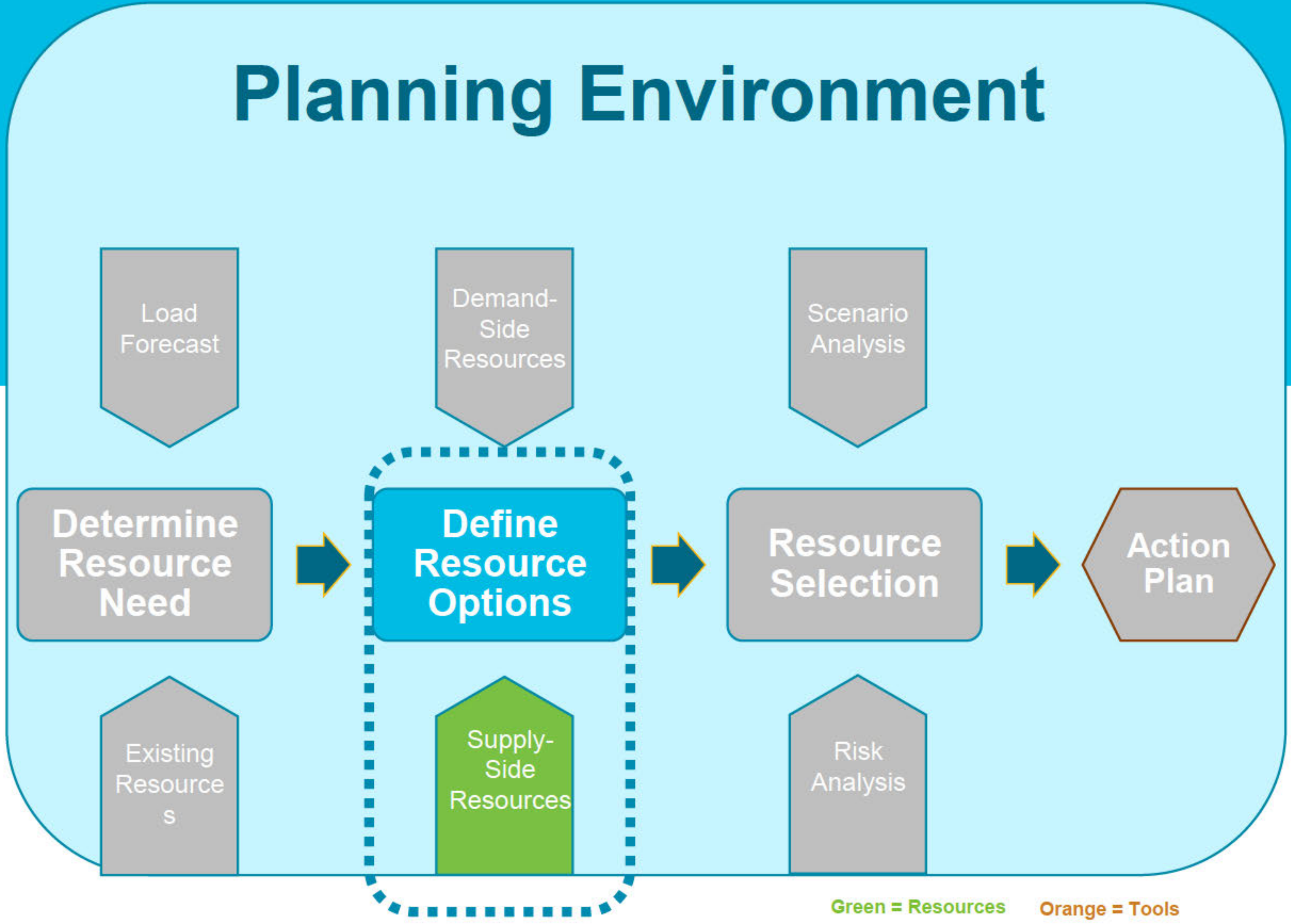
Incremental Supply-Side Emissions Reduction Options

Renewable Natural Gas

- Biofuels
- Clean Hydrogen
- Synthetic Renewable Gas

Carbon Capture

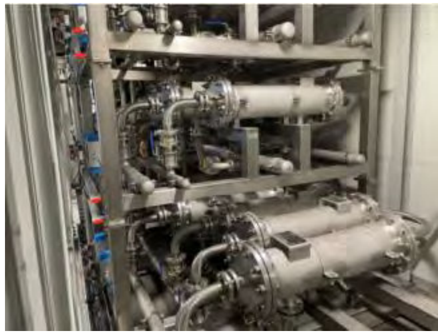
- Storage



Biofuel RNG as a Resource

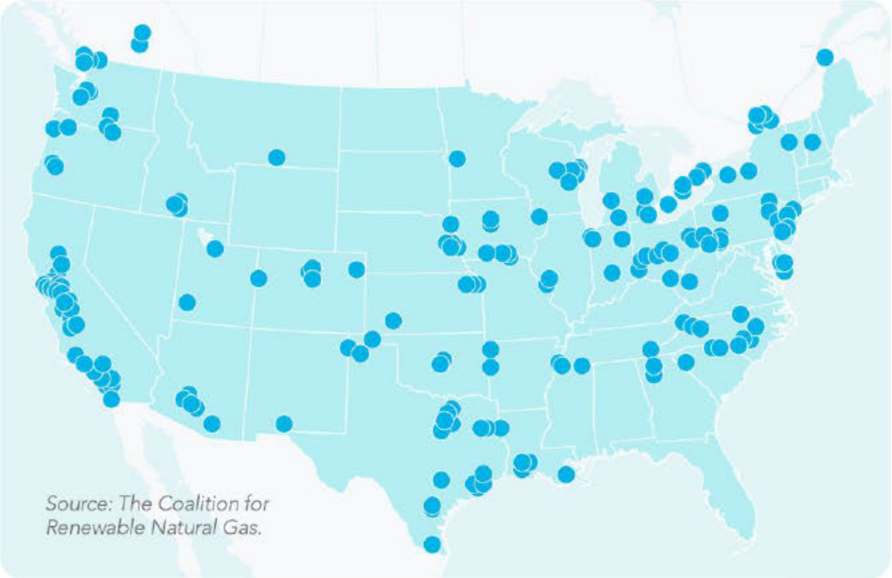
- Derived from waste methane resources from:
  - Landfills
  - Wastewater treatment plants
  - Agricultural wastes (e.g., corn stover)
  - Animal manures
  - Waste biomass
- Main components of an RNG project:
  - Raw gas production/capture (e.g., anaerobic digester or landfill gas well system)
  - Gas conditioning and cleaning system (removes various impurities and other gases to ensure RNG is pipeline quality)
  - Compressor (if needed)
  - Interconnection to local gas pipeline

Nitrogen removal system for large landfill RNG project



Membranes to clean RNG at Tyson Lexington facility (NW Natural project)

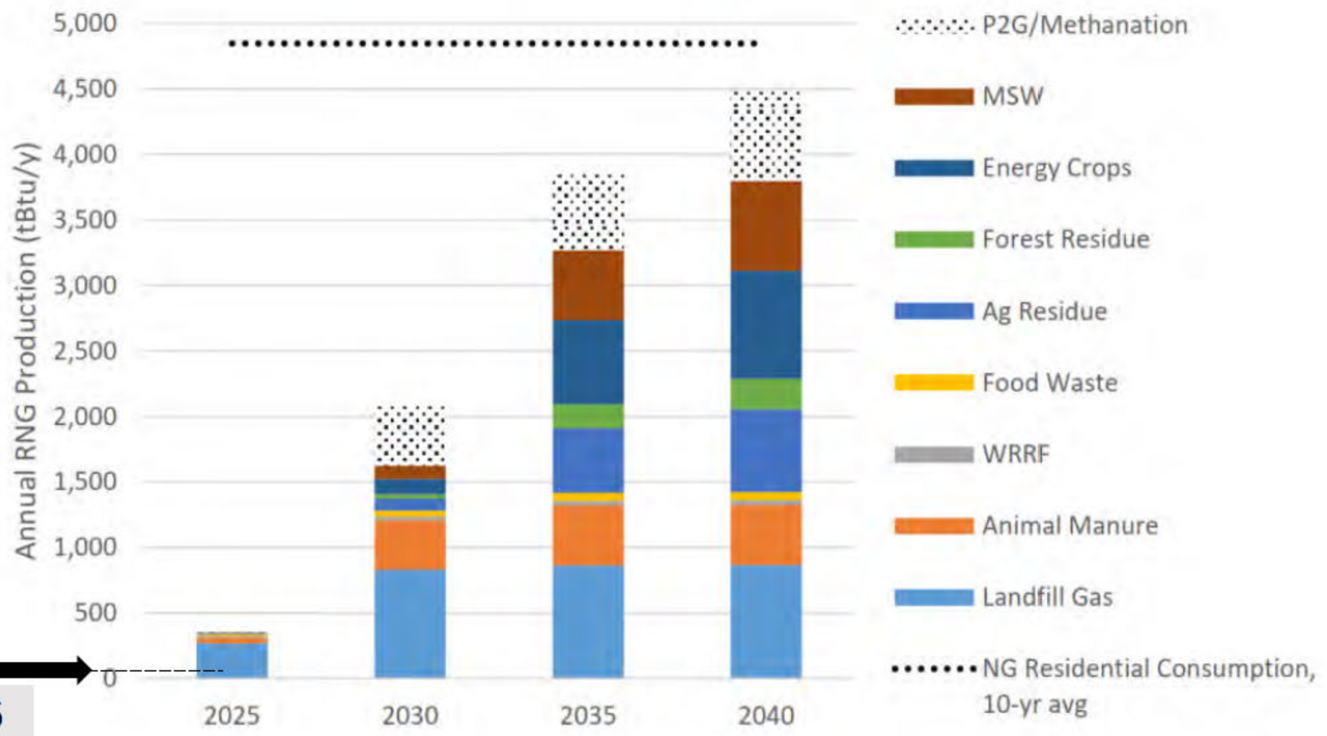
Current State of the RNG Market: Supply



- **188 operational RNG projects**
- **137 under development**
- **359% increase in operational RNG projects since 2014**

Today's RNG supply: 55 Trillion btus/year

Figure 2. Estimated Annual RNG Production, High Resource Potential Scenario, tBtu/y



Source: 2019 American Gas Foundation Study Prepared by ICF

Role of Utilities and Large Gas Customers in the RNG Market

- RNG has historically been sold into highly lucrative but highly volatile transportation fuel markets
- RNG project developers have less confidence in the stability of these markets and are seeking reliable long-term contracts at fixed prices to help hedge their revenue risks
- Natural gas utilities, large industrial users, and large institutional gas users are beginning to sign more long-term contracts for RNG to meet decarbonization goals
- Fixed-price contracts for RNG often represent a large portion of the total RNG produced by an RNG facility, but not all RNG produced; the project owner may sell a small portion of the RNG into the lucrative transportation markets
- Natural gas utility and large customer purchases of RNG provide an important "floor" price for RNG projects, which has helped RNG projects secure more affordable financing

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- 15-year contract with Archaea
- Landfill gas
- For heating and on-campus power generation
- Goal: carbon neutral by 2050

Port of Seattle
SEATTLE-TACOMA INTERNATIONAL AIRPORT

- 10-year contract with US Gain
- For heating and CNG vehicles use
- Goal: reduce carbon emissions 50

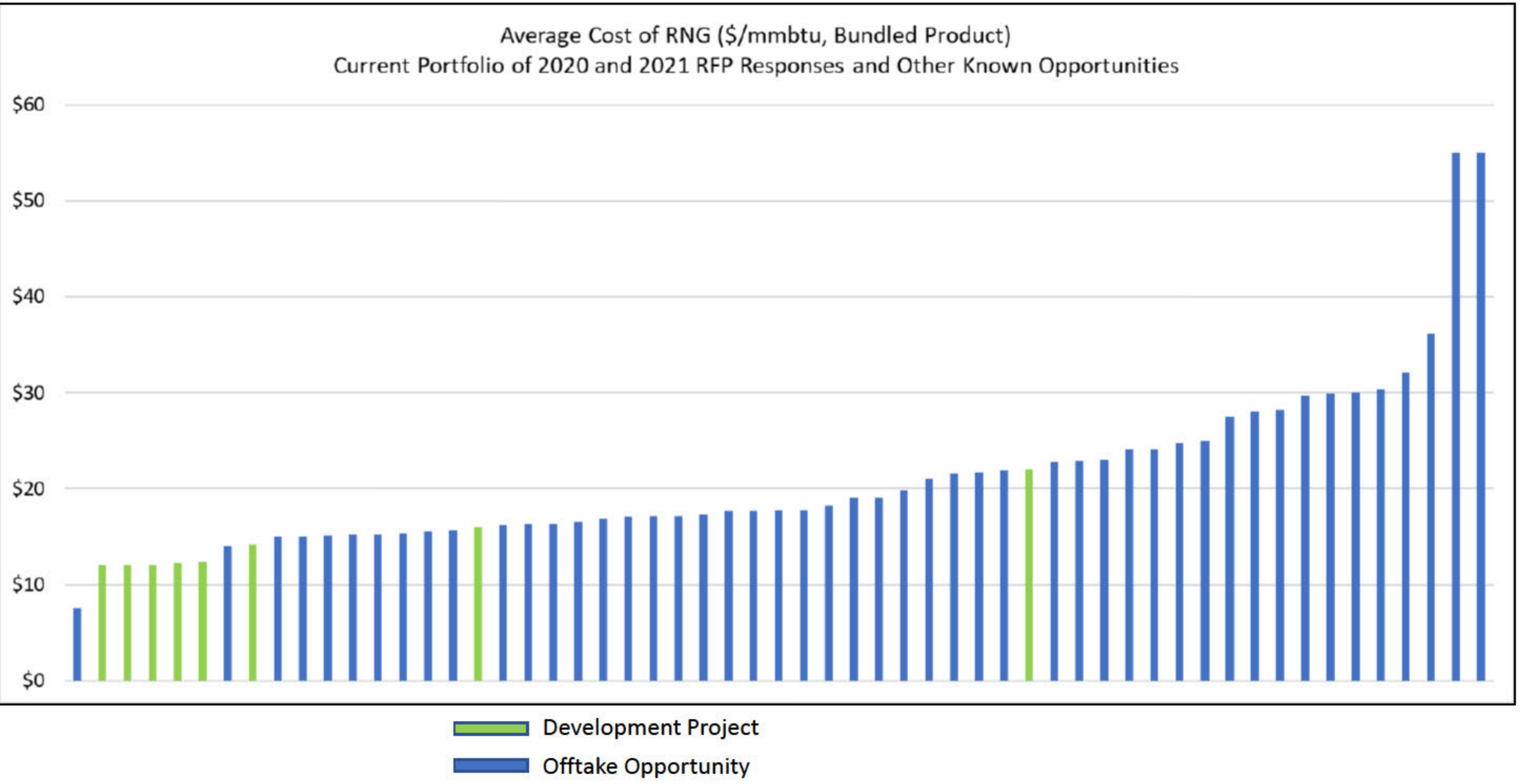
L'ORÉAL

- 15-year contract with Big Run Landfill
- For on-site manufacturing at multiple locations
- Goal: carbon neutral by 2025

NW Natural's RNG Market Activity

- **2020: began issuing annual RFPs for RNG Supply – first gas utility in the country to issue RFPs seeking RNG for all customers**
  - 2021 RFP yielded a "short list" of RNG resources available in the near term totaling 11% of our Oregon sales volume; currently conducting additional diligence on short list opportunities
  - 26 individual proposals received in 2021 process
  - High interest from developers and RNG project owners in long-term fixed price contracts
  - Regularly contacted in between RFP cycles with offers of RNG to meet S.B. 98 targets
- **Project development team working to develop low-cost RNG resources**
  - Development projects consistently evaluated as lower incremental cost than offtakes available through RFP processes and market outreach
  - Tyson, Lexington RNG project: began construction earlier this month; expected to be operational by early 2022
  - Project team continues to evaluate additional project opportunities that yield projected incremental costs of less than offtake-only opportunities
- **Executing first offtake contracts for RTCs as a result of 2020 RFP**
  - Executed contract with Element Markets for RNG from two facilities
  - Second contract currently being finalized

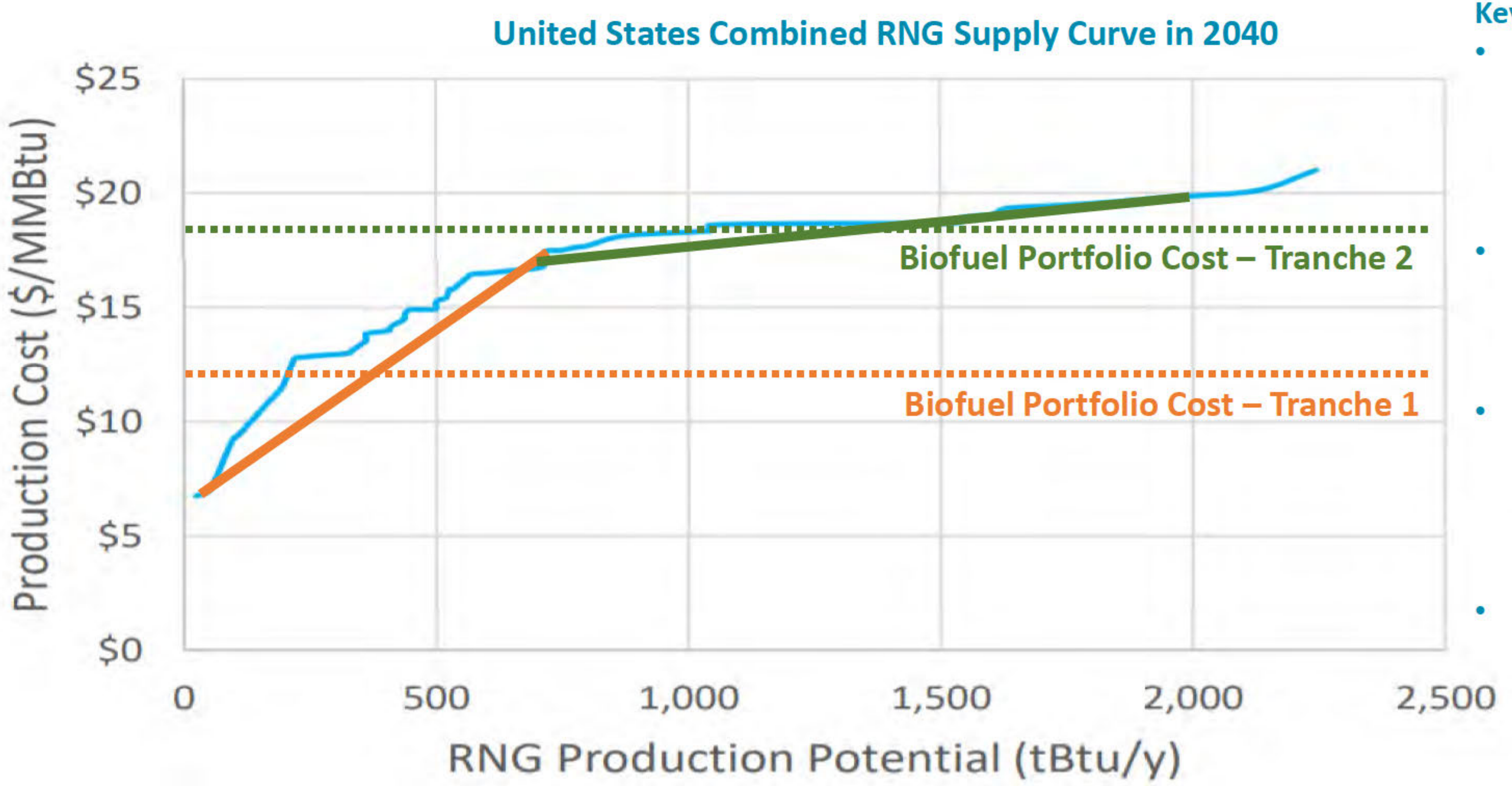
Significant RNG Resources Available and Currently Under Evaluation



- Chart reflects 2020 and 2021 RFP responses, as well as the development projects NW Natural is currently evaluating
- Total production represented in this chart: 35.3 million mmbtu/year, or about 49% of all of NW Natural's annual sales in Oregon in 2021

Biofuel RNG Assumptions

NW Natural®



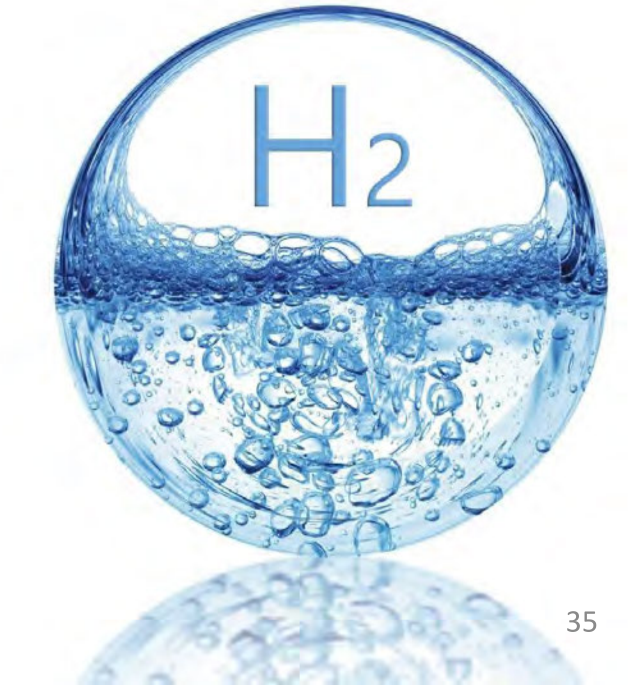
Key Assumptions:

- Maximum available RNG to Oregon's gas utilities is double the population weighted share of the national resource
- RNG Resources are not all available at all times, so using a traditional supply curve is inappropriate
- 1/3 of available resource (~15 million MMBtu per year for NW Natural) can be acquired for a portfolio cost of $12.25/MMBtu
- The remaining 2/3 of the resource (~31 million MMBtu) can be acquired for a portfolio cost of $18.75/MMBtu

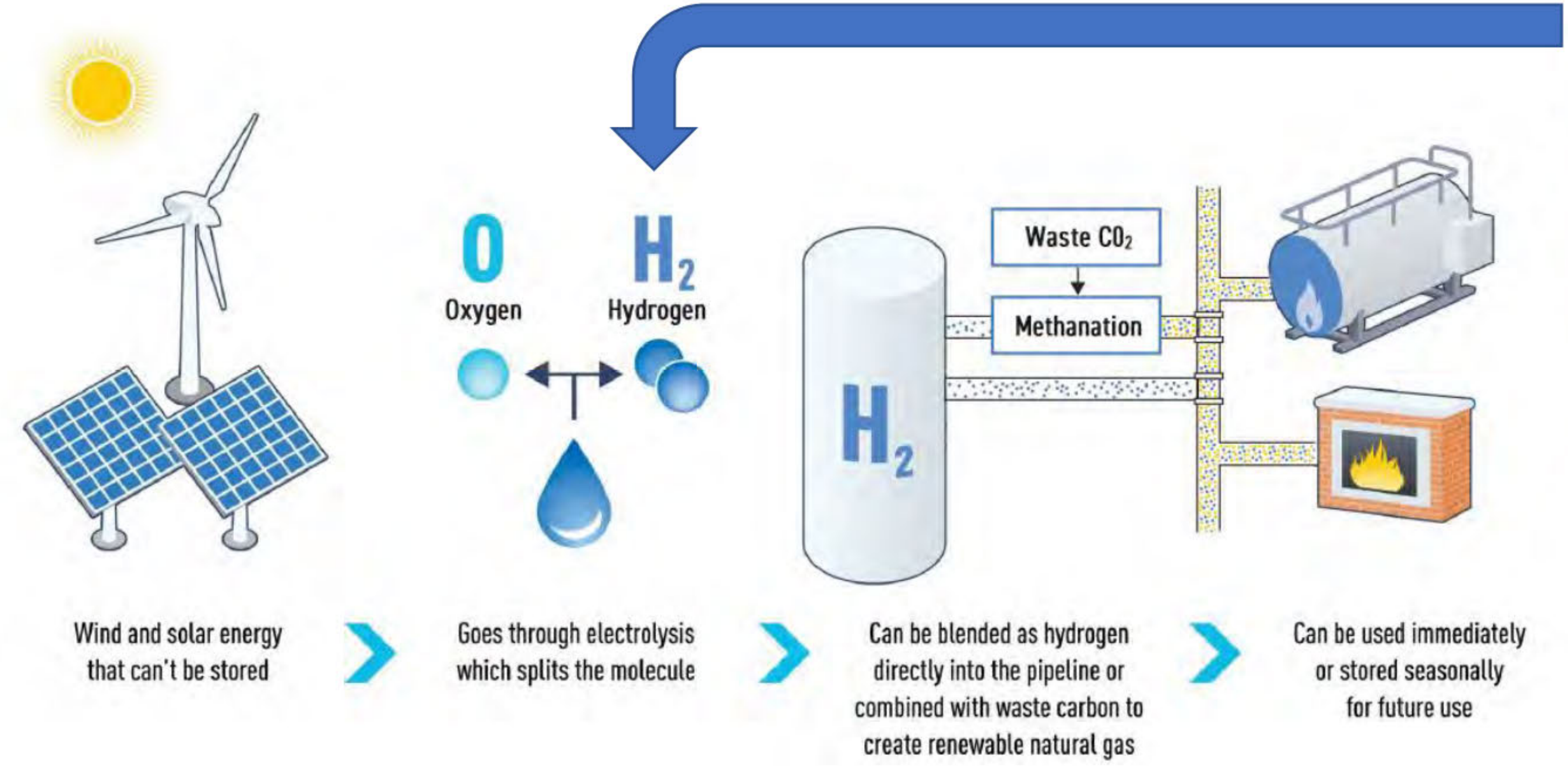
Supply Curve Source: "Renewable Source of Natural Gas." American Gas Foundation Study Prepared by ICF (2019)

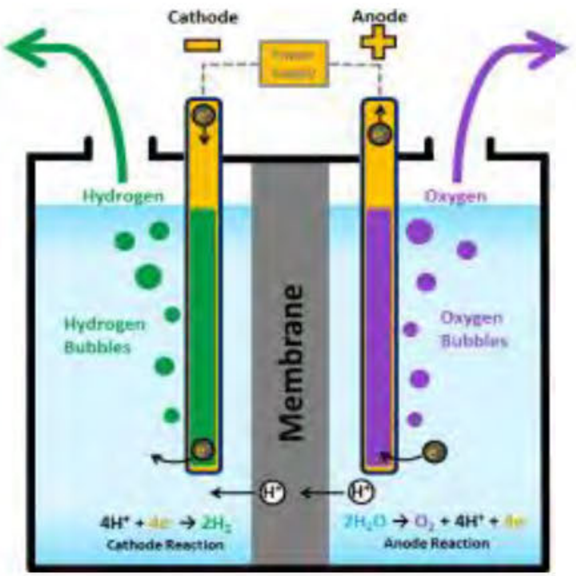
Hydrogen Benefits

Needed as key component of carbon-free future	No reasonable pathway to decarbonizing without hydrogen
Fits into current gas operations	Distribution | Storage | Customer Appliances
Numerous sources	Electricity | Biomass | Natural gas
Pathway to decarbonize hard to decarbonize sectors	Aviation, transportation, industry, marine



Electrolysis / Power to Gas / Green H_2



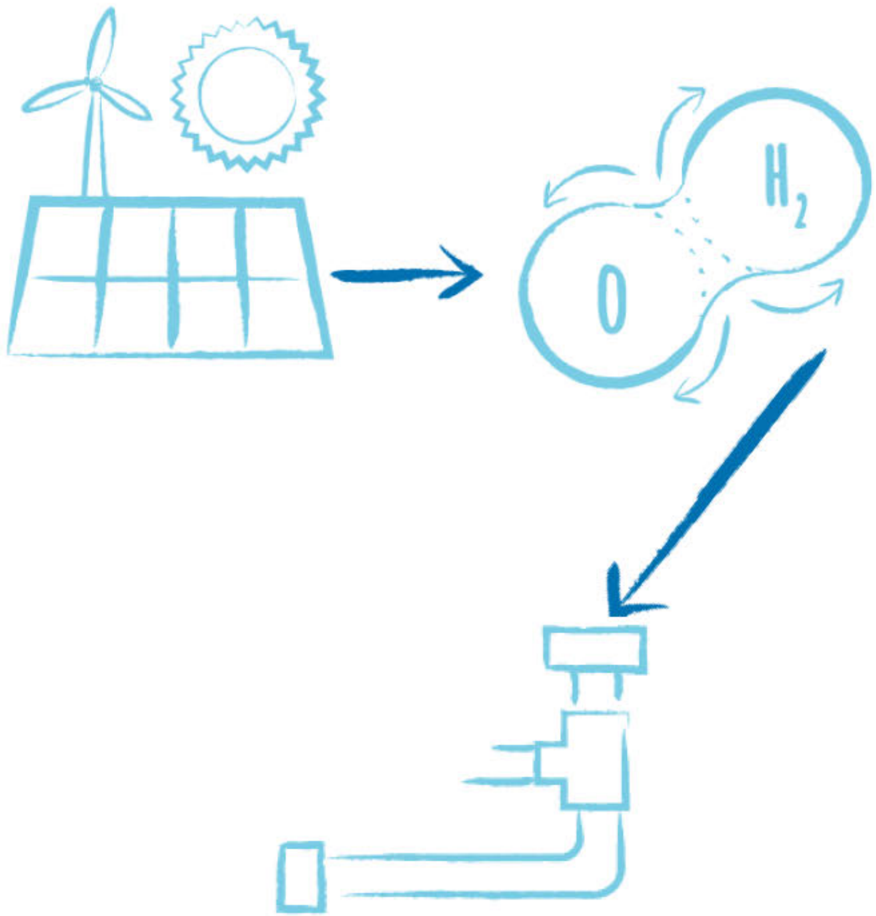


Source: DOE

NW Natural®

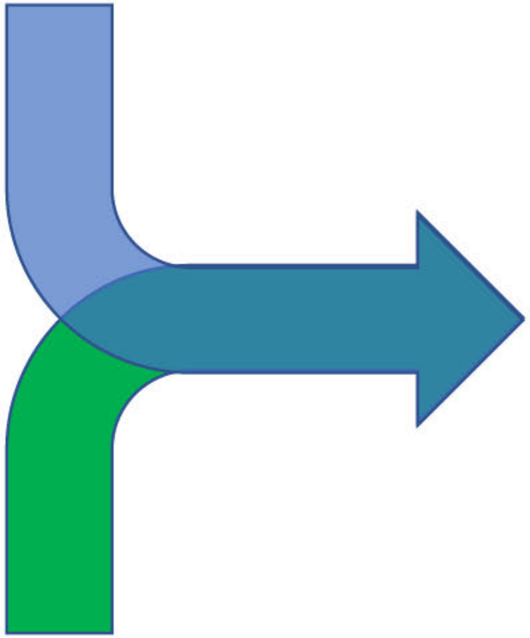
Green Hydrogen

- Takes advantage of curtailed renewables
- Provides grid benefits (ancillary services) to lower rates
- Simple messaging
- Lower capital cost to methanated hydrogen
- Limitations
    - Blend % limits (system and appliance compatibility)
    - Small scale
    - No transmission injection options



2021 Blending Projects

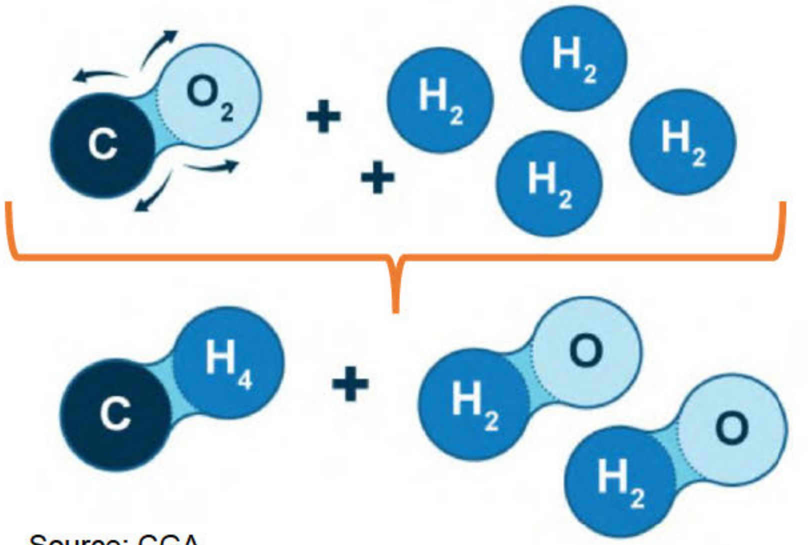
Enbridge (Toronto)	2%, construction started
ATCO (Edmonton)	5%
CenterPoint (Minneapolis)	1MW electrolyzer, construction started
NJNJ	< 1 MW electrolyzer, construction started
HyDeploy (Keele University, UK)	20% blend wrapping up
H21 – UK	100% hydrogen network underway



Methanated Green Hydrogen (Synthetic Gas)

NW Natural

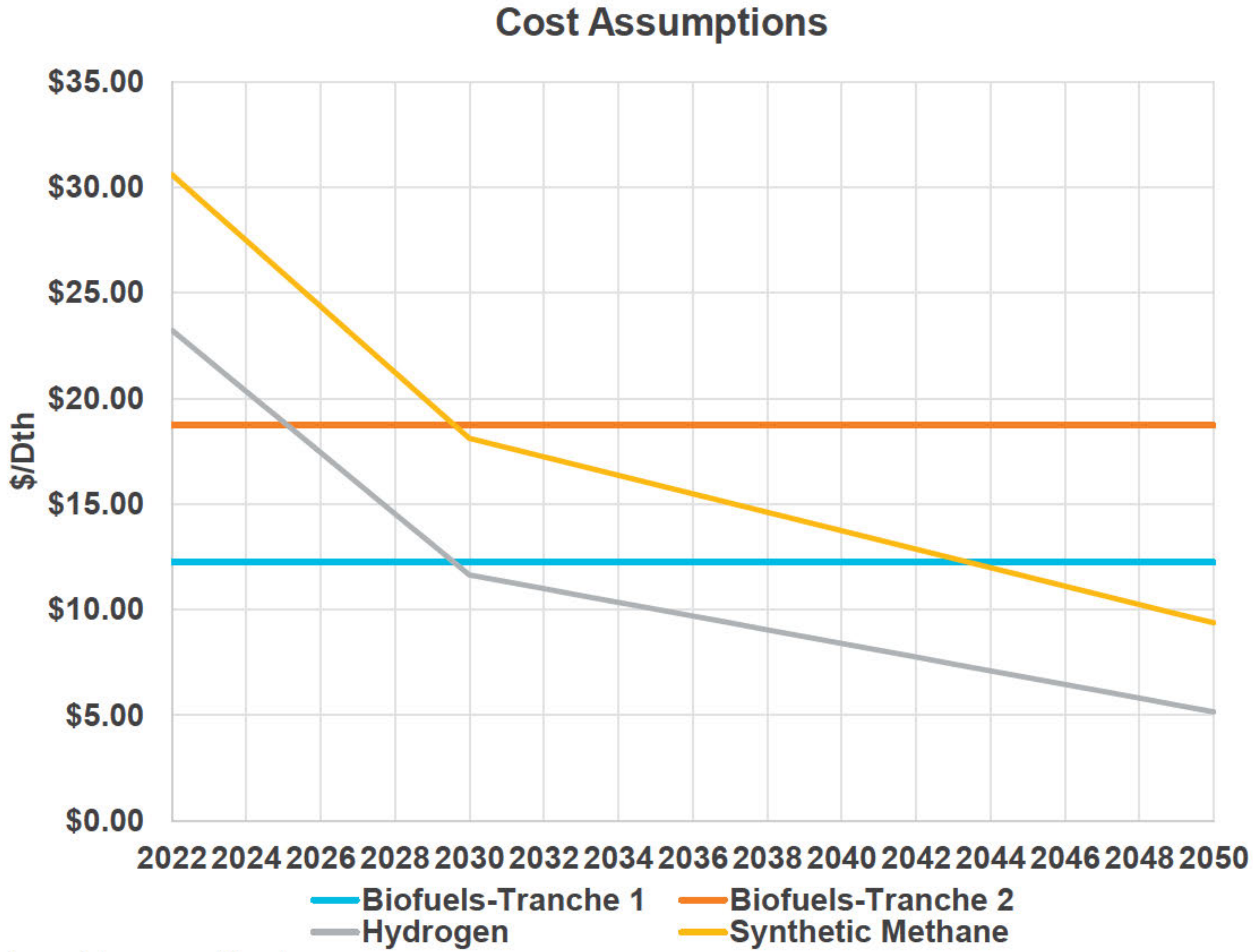
- Identical electrolytic hydrogen generation as previously described
- Similar costs to green hydrogen even with lower efficiency
    - Enables high electrolyzer utilization
    - Enables large scale production plants
- No blending % limit (system and appliance compatibility)
- No system energy delivery loss
- Need steady and low-cost supply of CO_2



Source: CGA

Total Renewable Gas Supply Curve

NW Natural®



Hydrogen data sources: Bloomberg

Availability Assumptions

Renewable Supply Type	Max Supply Available to NW Natural
Biofuel RNG Tranche 1	15.4 Million MMBtu
Biofuel RNG Tranche 2	30.7 Million MMBtu
Green Hydrogen for Blending	20% of Deliveries
Synthetic Gas from Green H2	Unlimited

Drivers of Cost Reductions

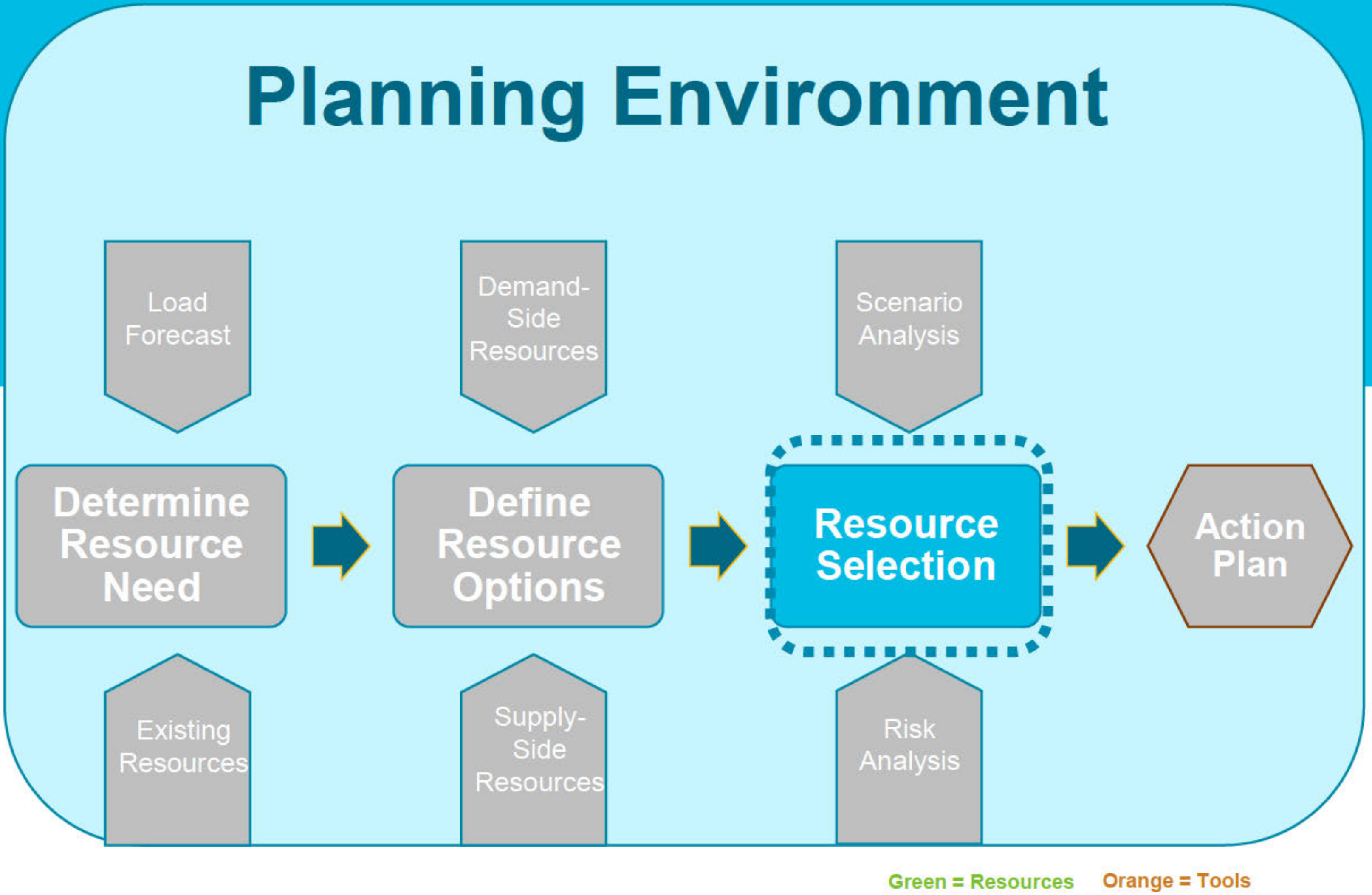
- Lower cost renewable power
- Continued declines in equipment costs
- Growing global supply of hydrogen

What might compliance look like?

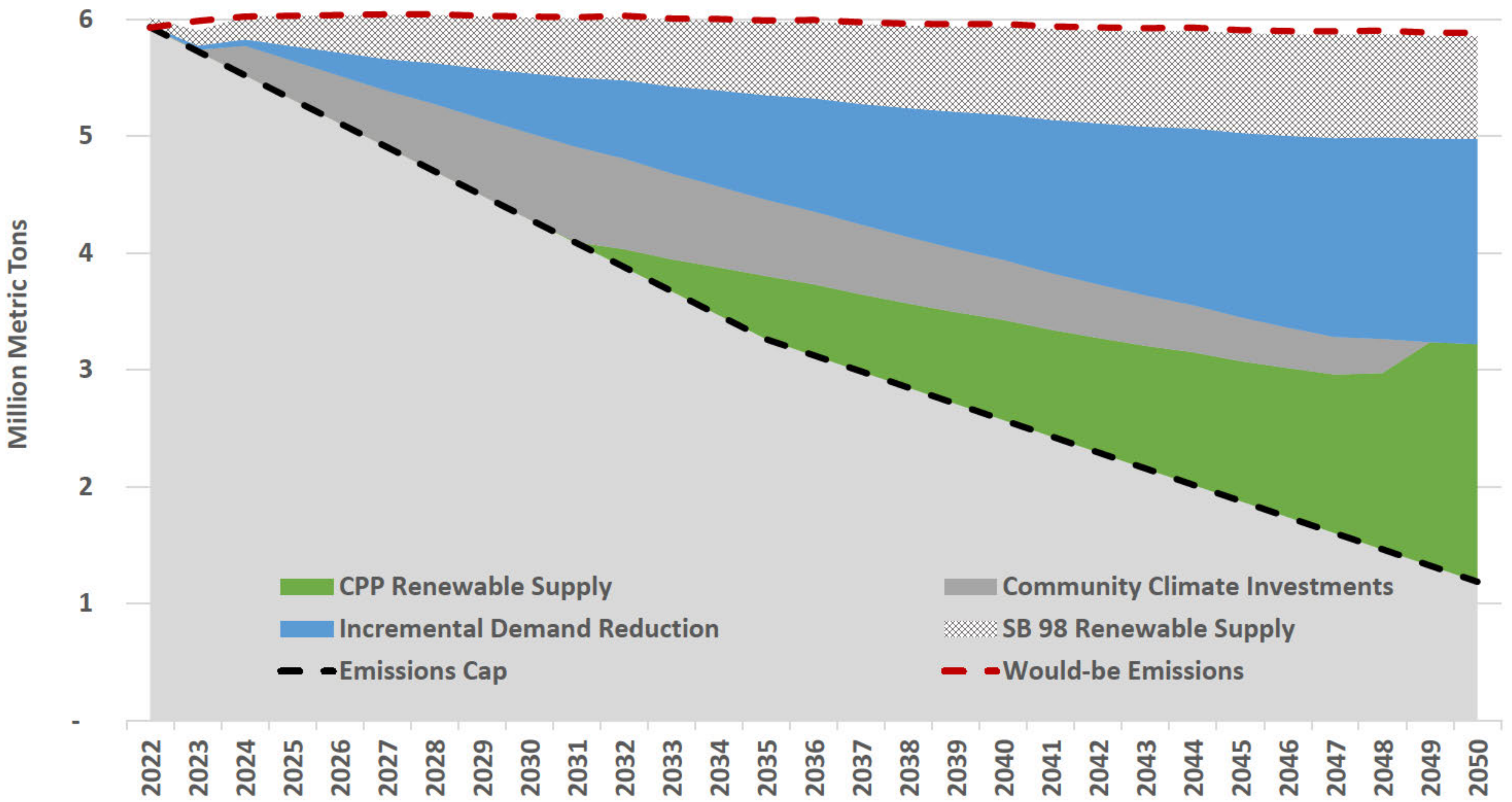
Reminders:

- This analysis does not apply the robust tools used in IRP planning
- The CPP rules are a draft and still under consideration
- The best options for customers are likely to evolve as time moves forward and technologies progress

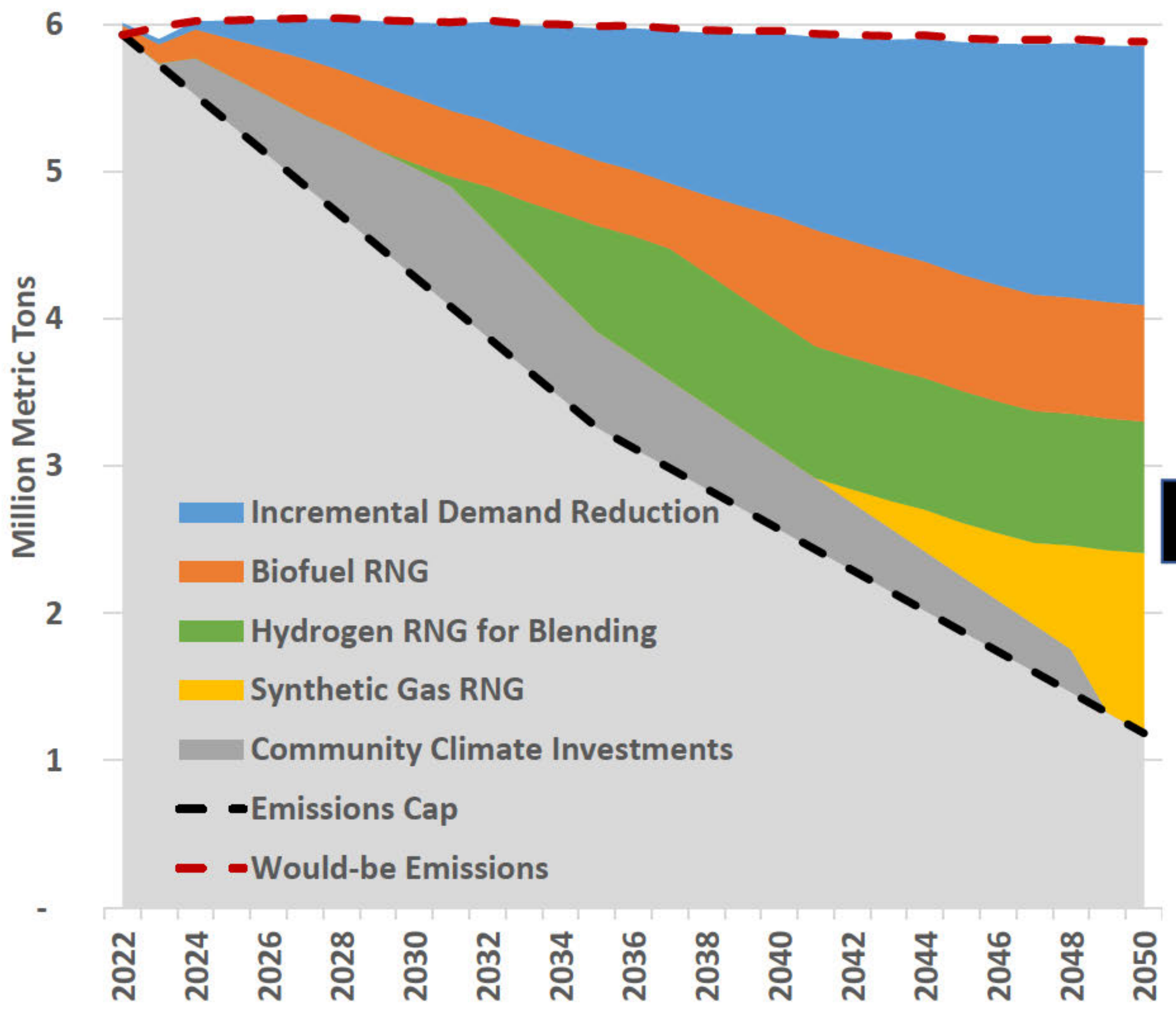
What incremental actions could be taken to comply with the CPP?

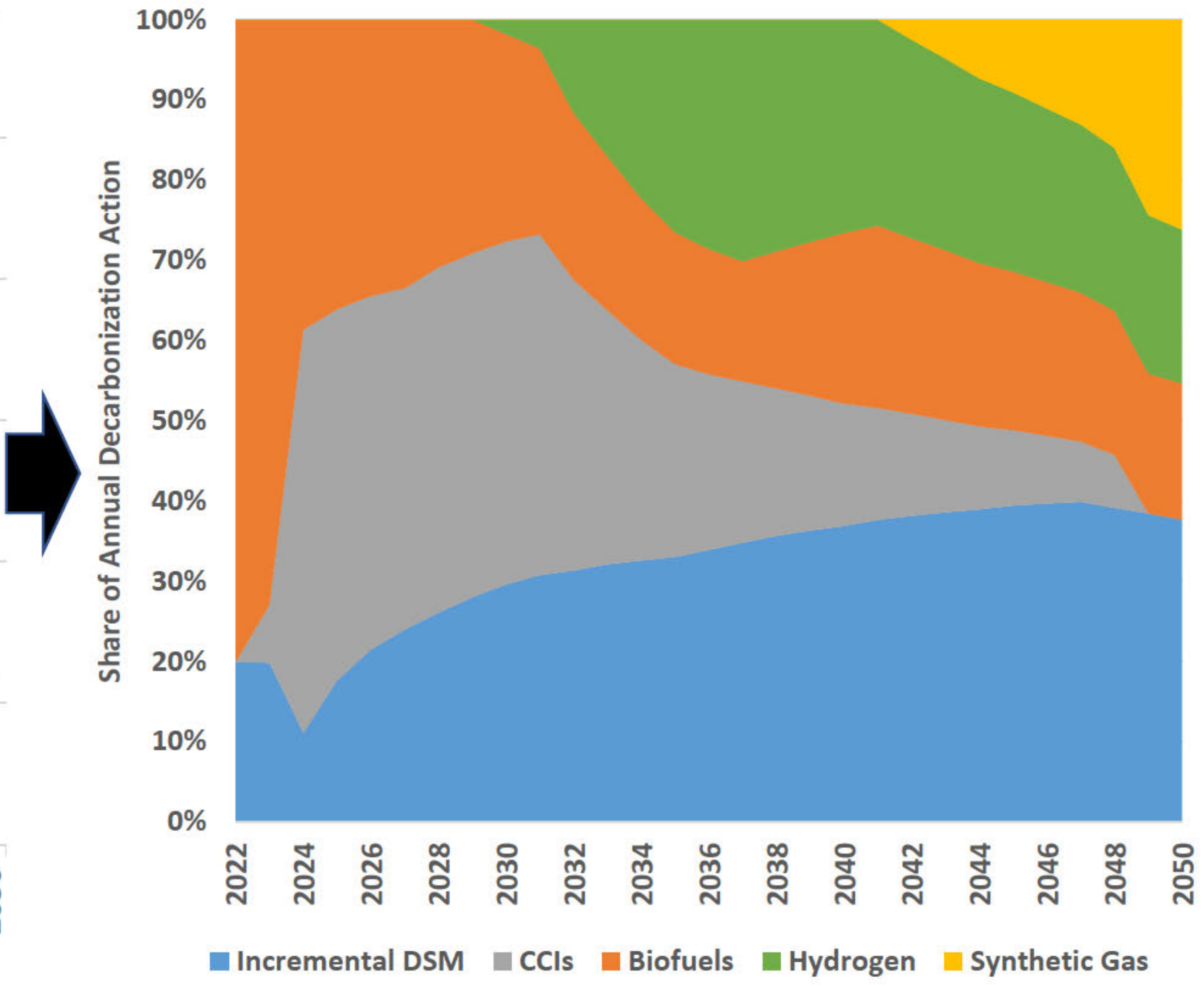


Draft CPP Compliance Strategy Summary

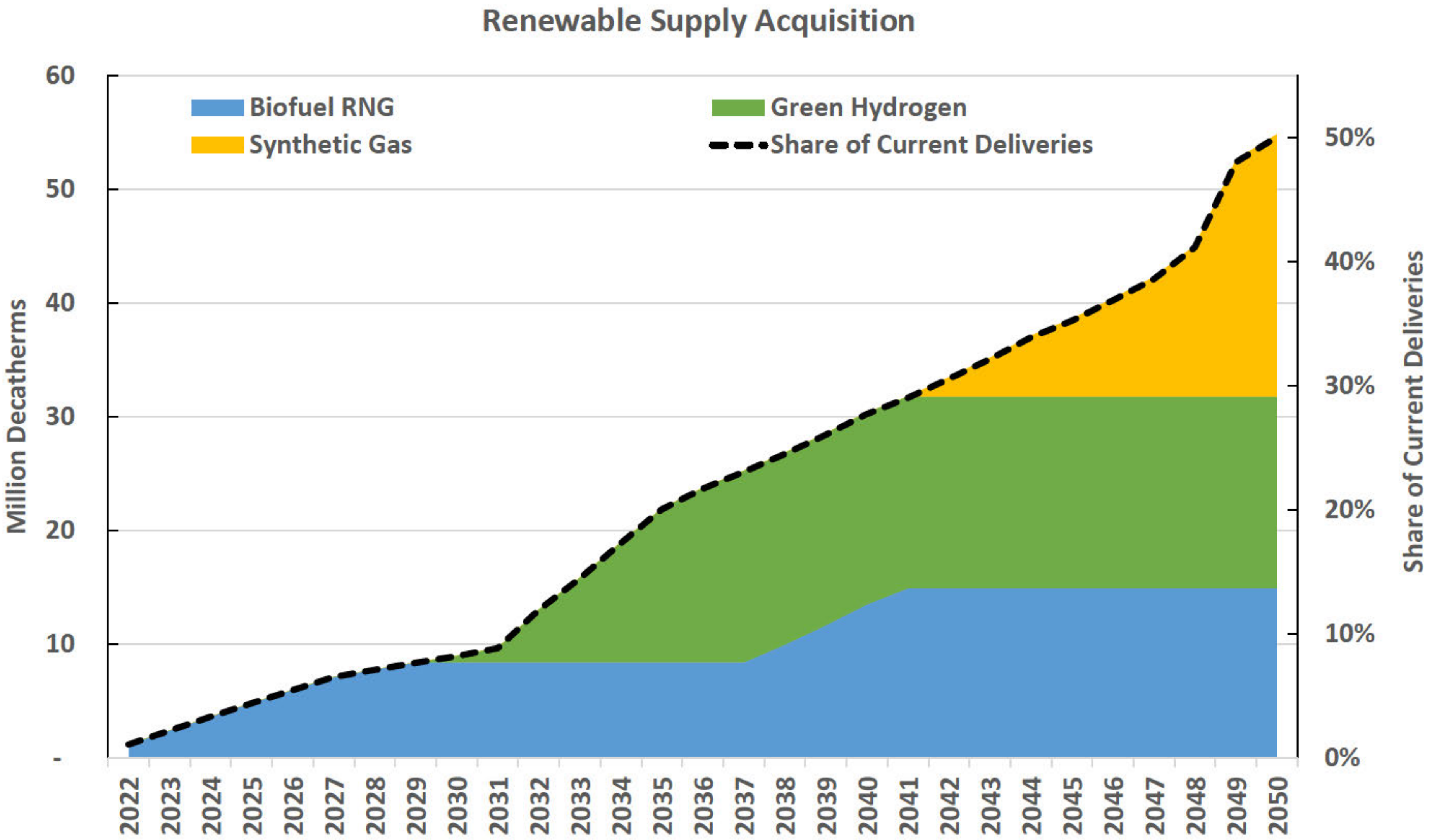


Draft CPP Compliance Strategy Summary



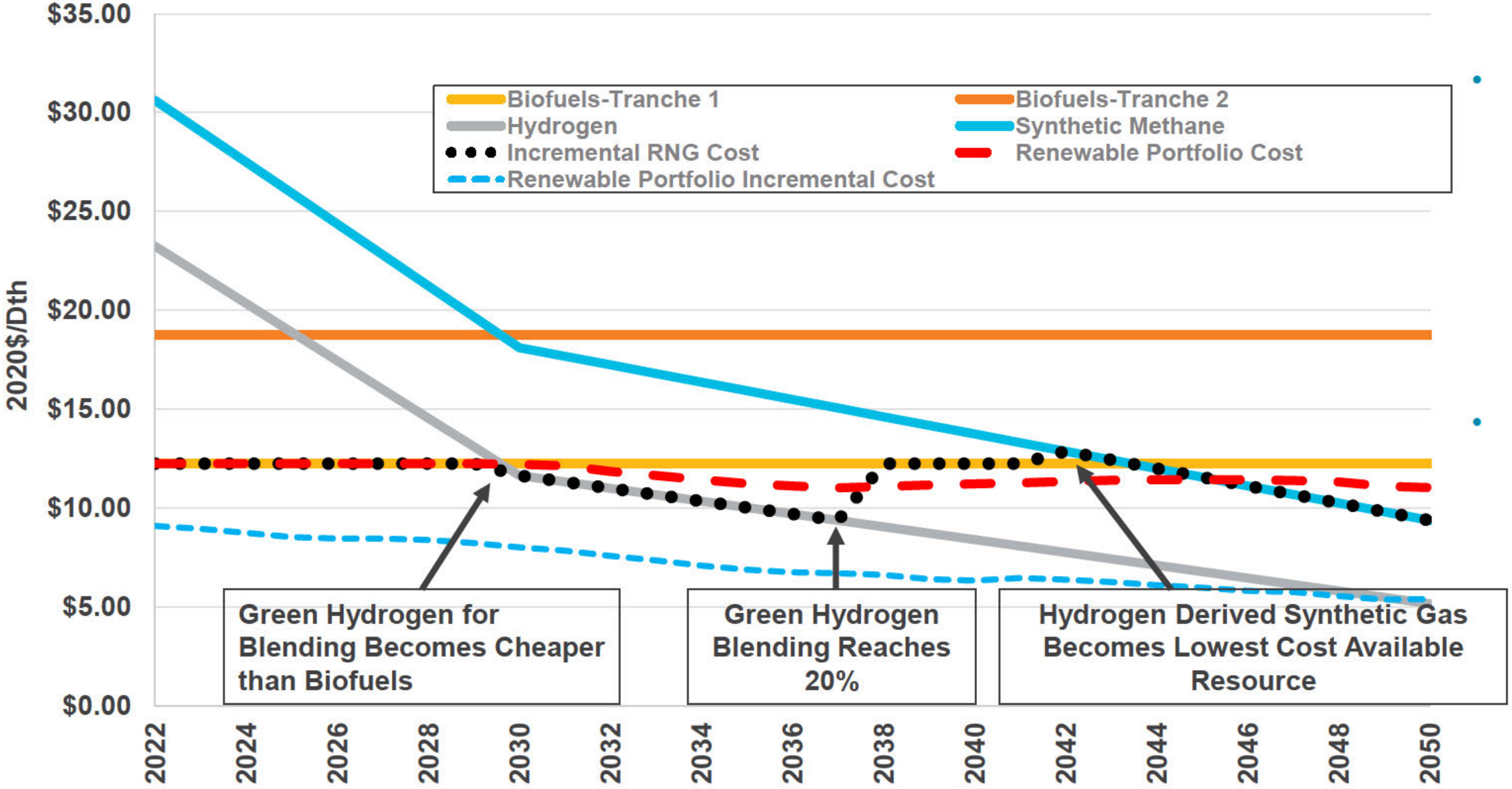


Draft Renewable Supply Results



- **Shows total renewable portfolio, including both SB 98 and CPP needs**
- **Biofuels RNG reach ~13% of current deliveries by 2050**
- **Total renewable portfolio represents ~8% of current deliveries in 2030 and ~50% of current deliveries in 2050 (representing 72% of 2050 deliveries)**
- **Blended green hydrogen represents 20% of deliveries in later years, with hydrogen derived synthetic green methane filling in the portfolio in the 2040's**

Draft Renewable Supply Acquisition



- Maximum biofuel penetration in any year is 14% of current deliveries and represents roughly half of Oregon's population weighted share of the national biofuel RNG resource
- Renewables reach 72% of deliveries in 2050

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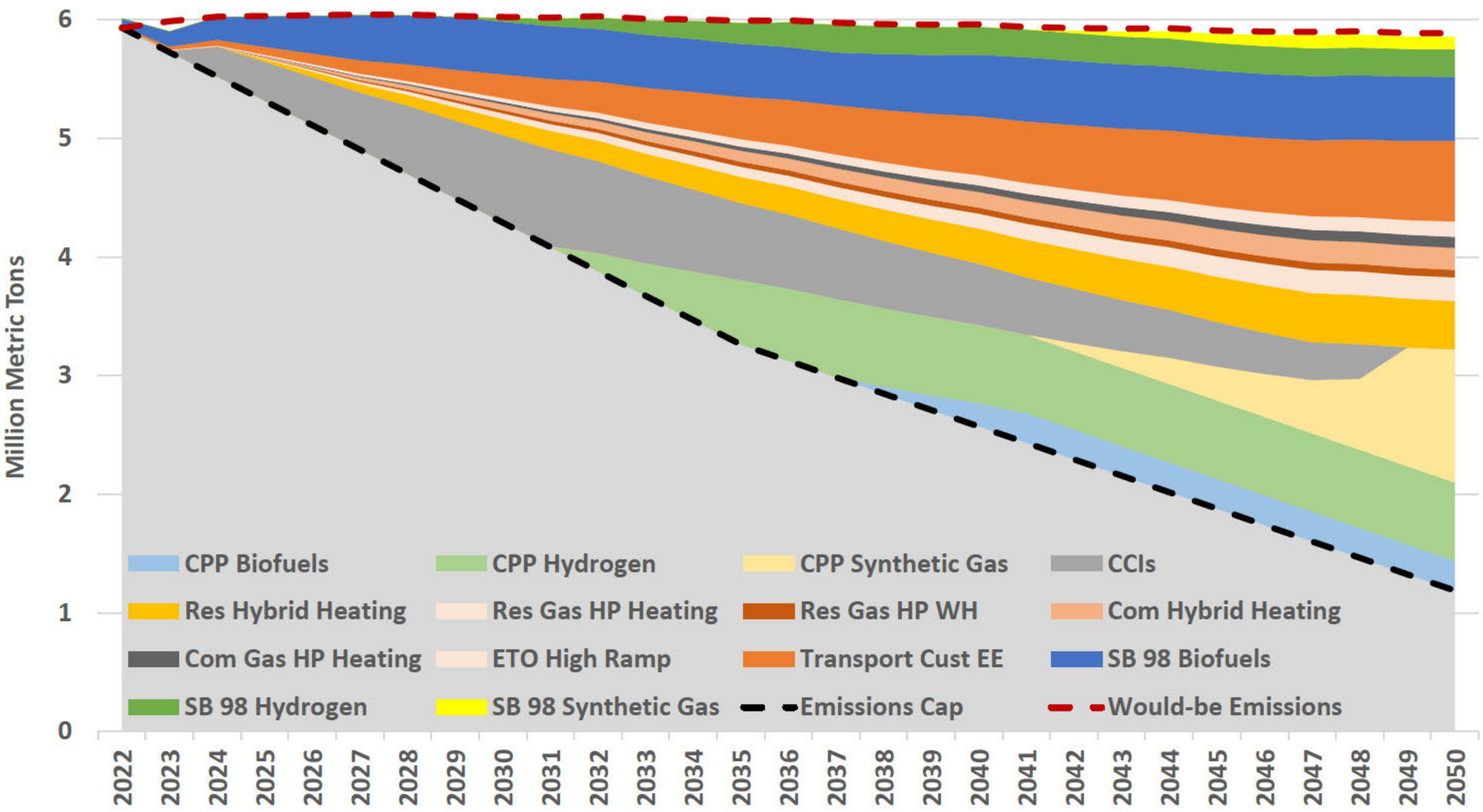
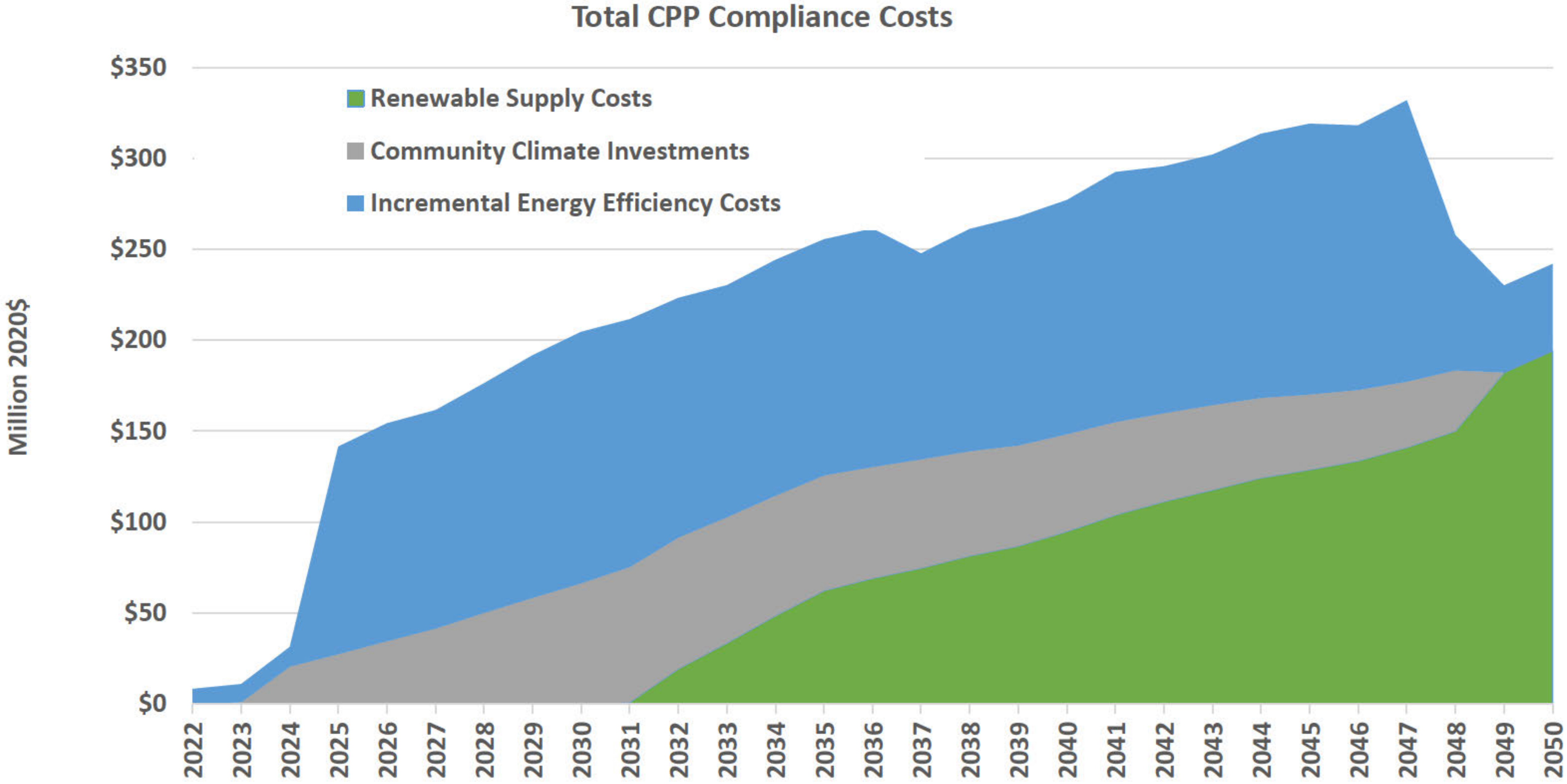
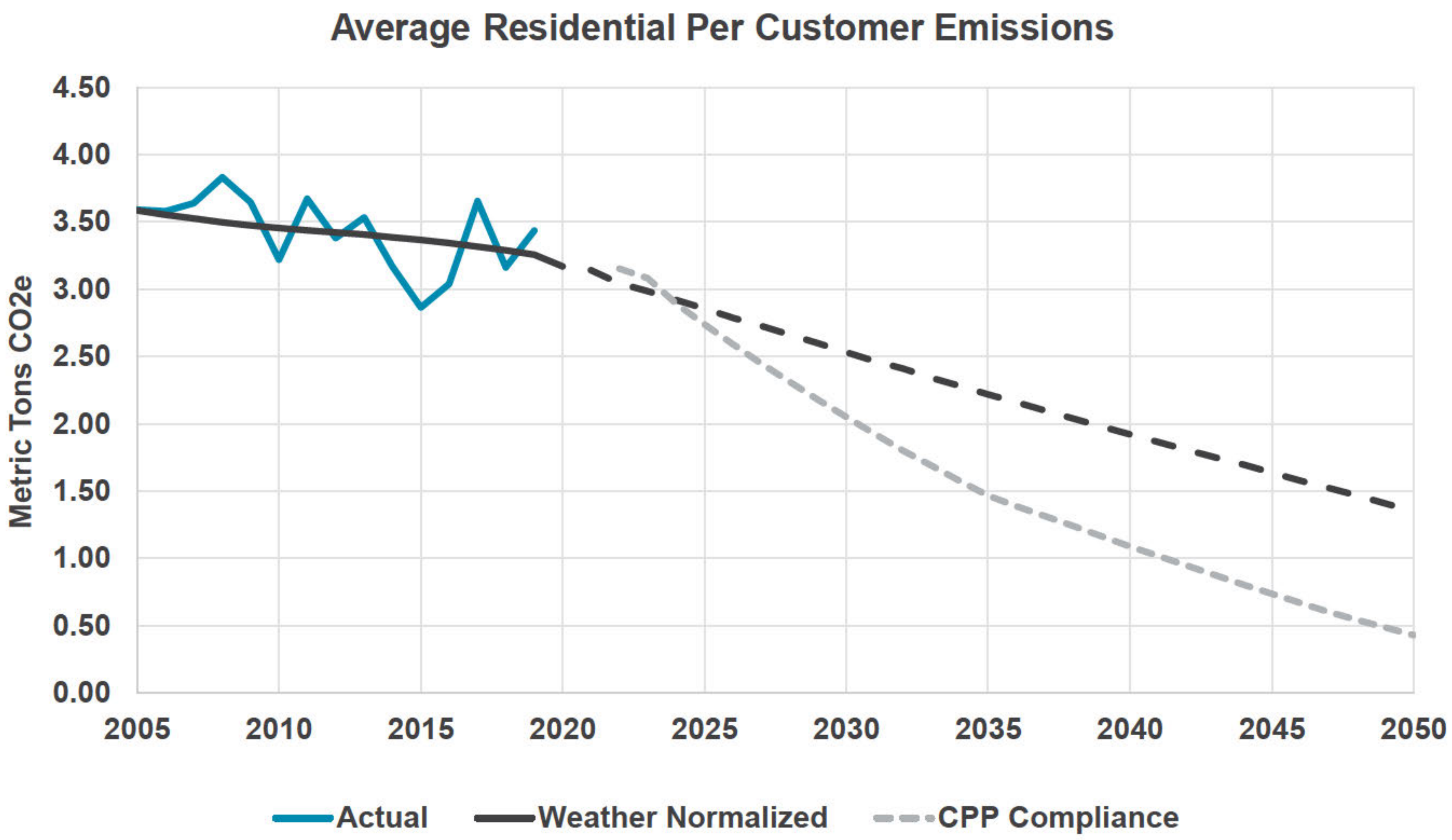
Draft Base Case CPP Compliance Strategy



Draft CPP Compliance Costs

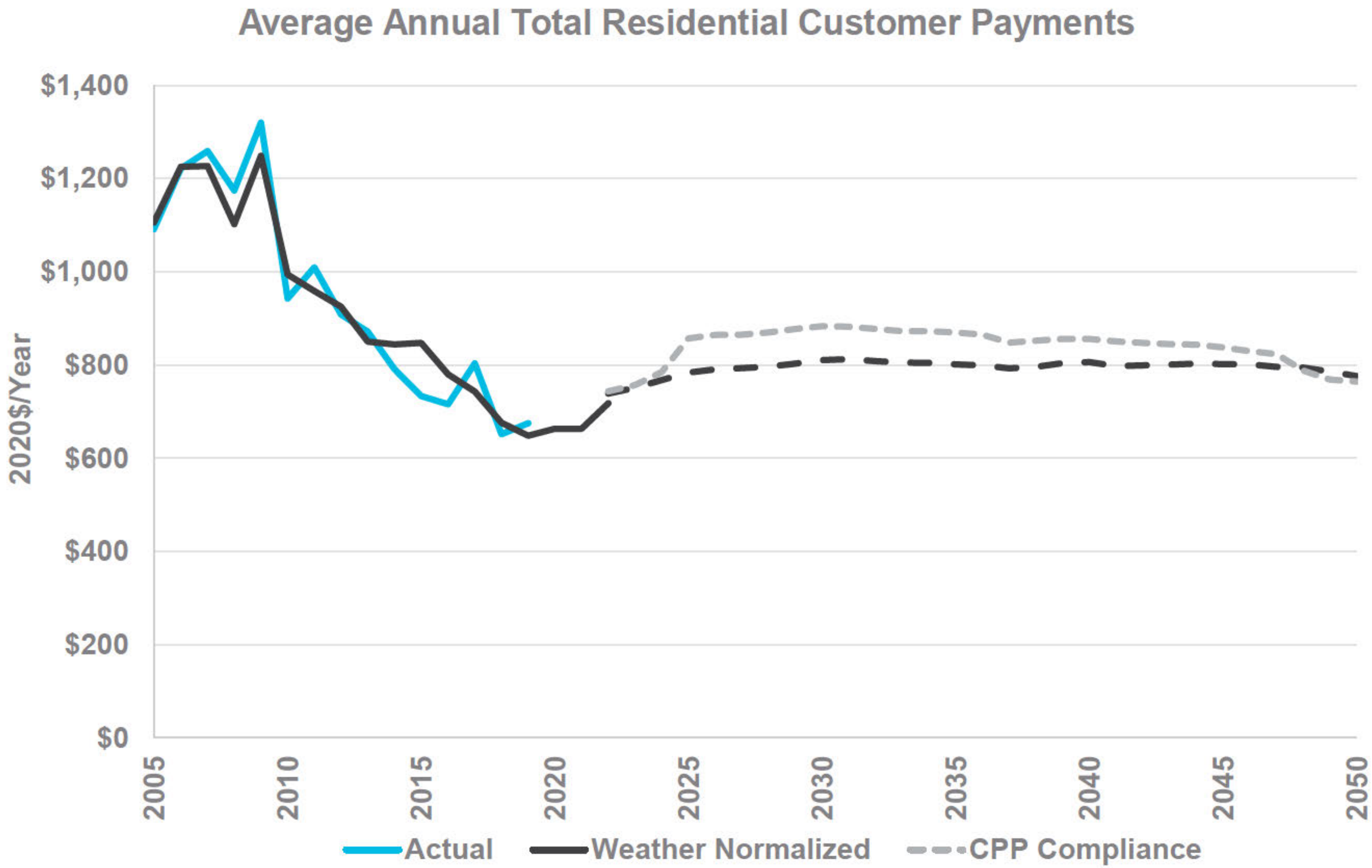


Draft Residential Emissions Under CPP Compliance



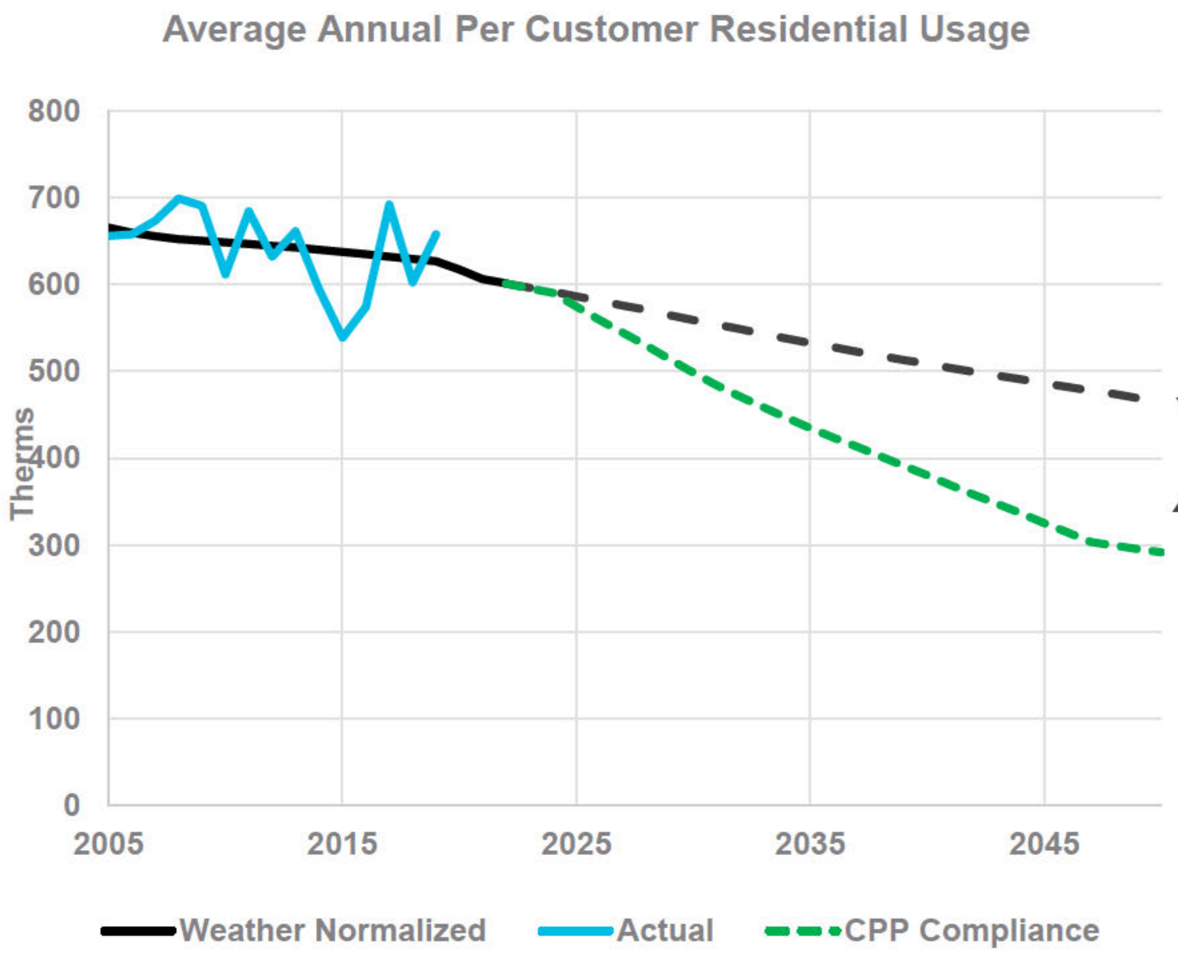
Total NW Natural Residential Emissions in 2050 represent less than 0.5 Million Metric Tons of CO2e (<1% of Oregon's current emissions)

Impact on Residential Total Gas Utility Payments



- **Total utility bills depend upon usage and utility rates**
- **Total bill = Usage x Total All-in Rate**

Constructing Impact on Customer Bills: Combined Impact of Usage and Utility Rates



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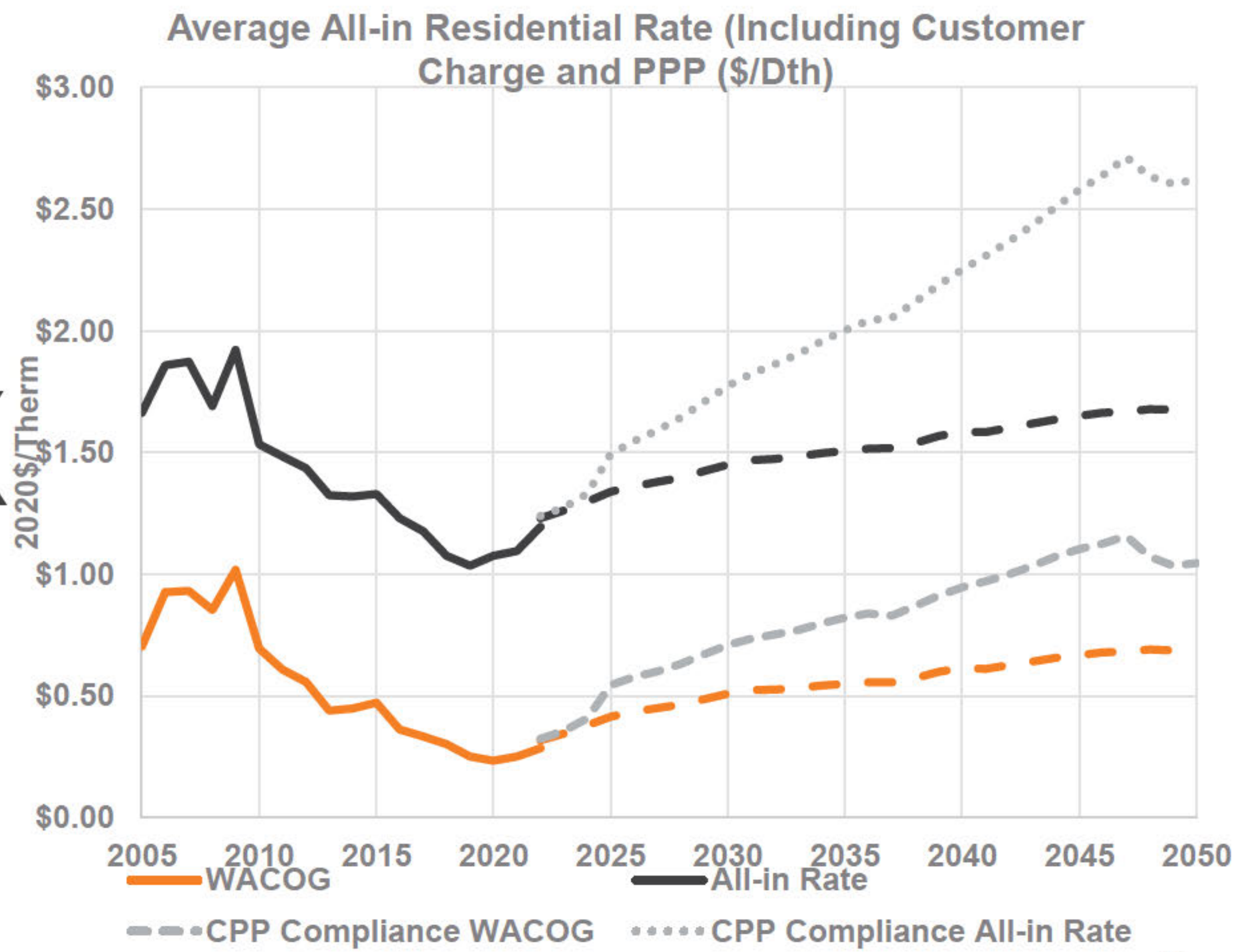
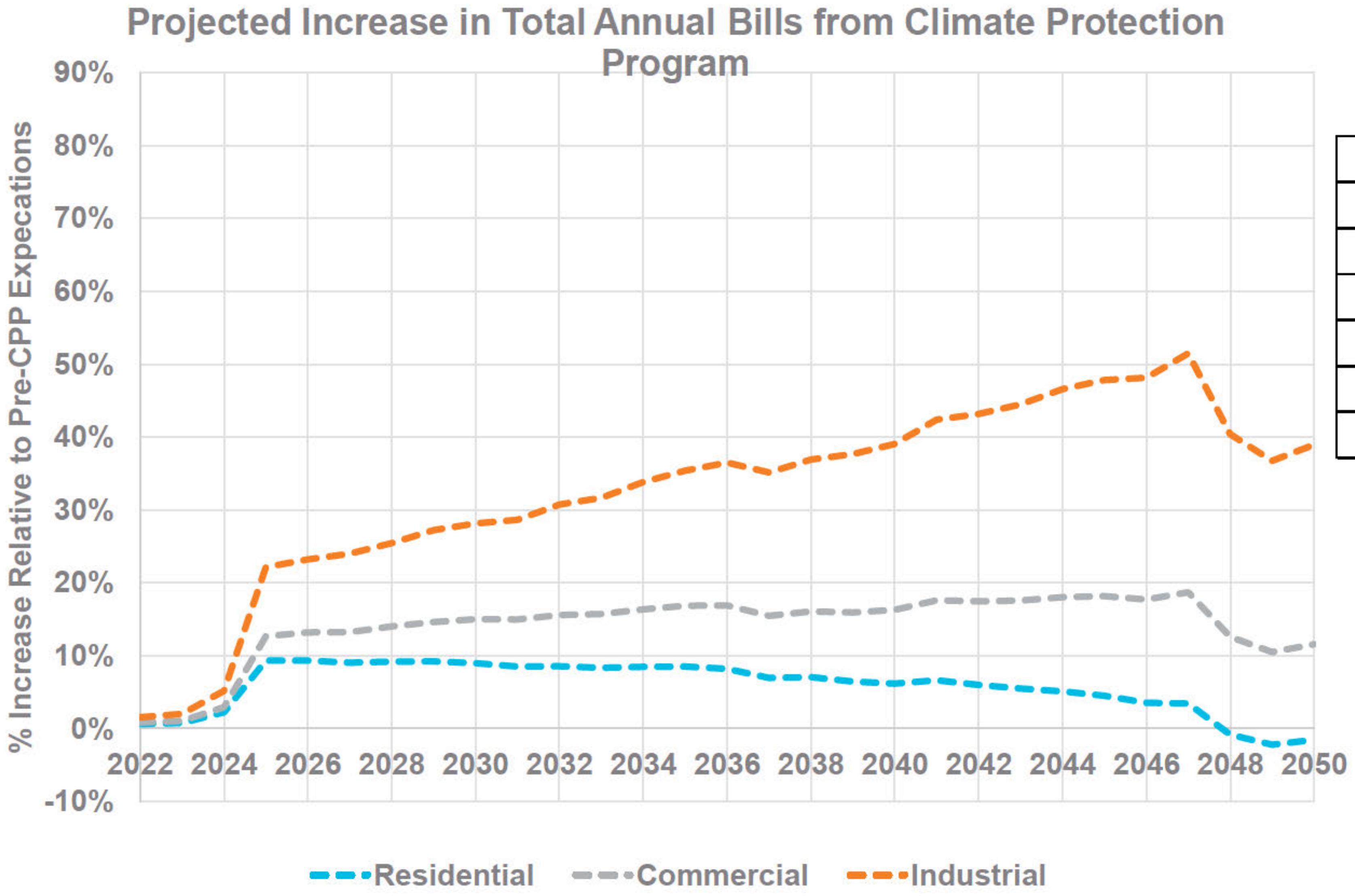


Impact of CPP to Customer Annual Gas Bills



	Residential	Commercial	Industrial
2022	1%	1%	2%
2025	9%	13%	22%
2030	9%	15%	28%
2035	9%	17%	35%
2040	6%	16%	39%
2050	-2%	12%	39%

*Impact shown relative to pre-CPP expectations, including SB 98 and expected energy efficiency action

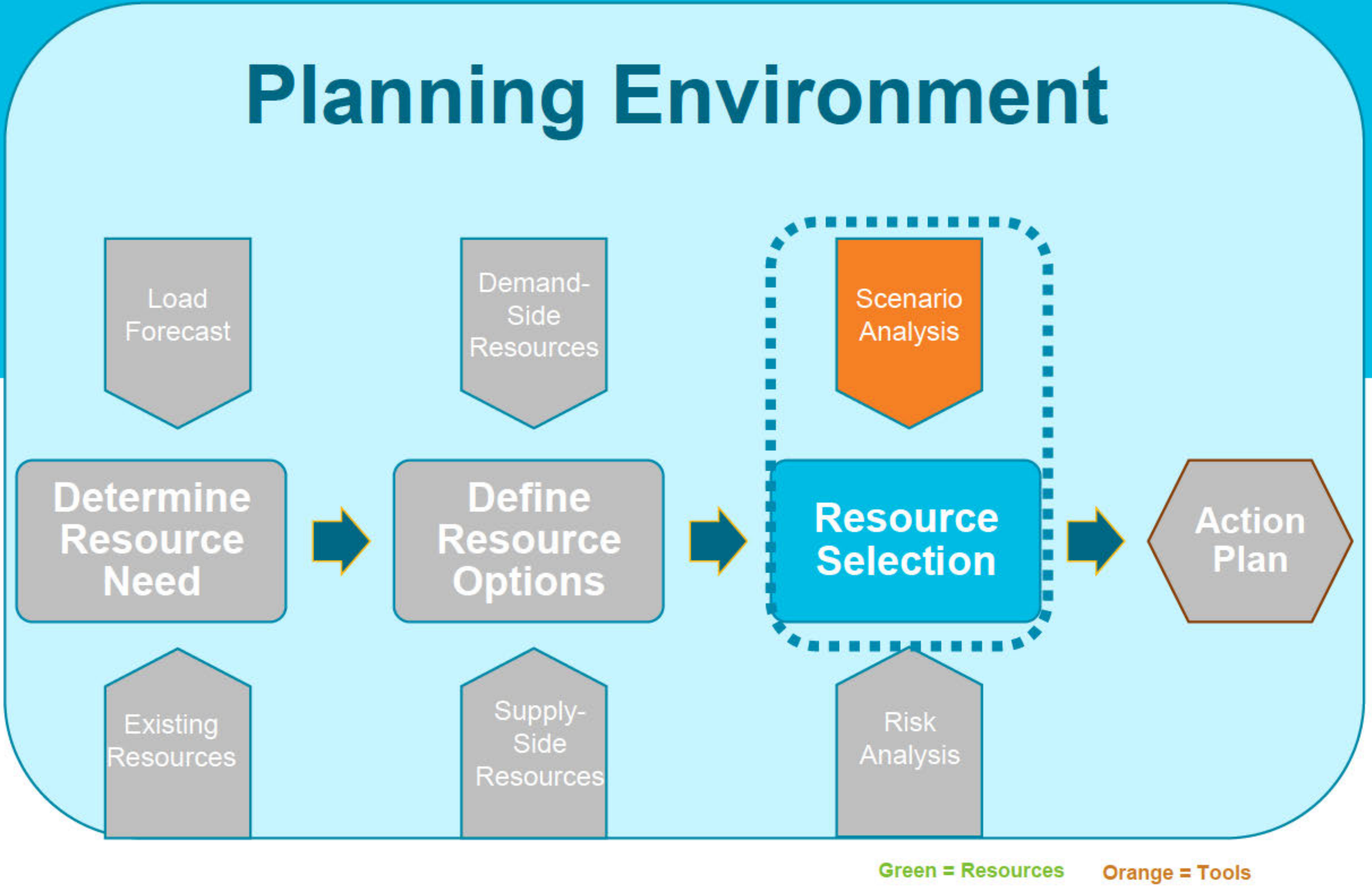
Alternative Scenarios Analyzed

OPUC Staff Directed Scenarios:

- Restricted RNG Supply
- Customer Decline
- More Aggressive Compliance Targets
- No Community Compliance Investments

Additional Scenarios Considered:

- Federal Renewable Gaseous Fuel Support
- Community-minded Voluntary Programs



Key Scenario Assumptions

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OPUC Staff Directed Scenarios:

- **Restricted RNG Supply**
  - Biofuel RNG restricted to half of SB 98 targets and RNG portfolio tranche 2 cost is applied to all biofuel RNG. Hydrogen and Synthetic gas costs use Syngas cost assumptions
- **Customer Decline**
  - Current IRP forecasted load growth through 2025; no new customers beginning from 2025 through 2030; -0.75% customer growth beginning in 2031 through the end of model's time horizon.
- **More Aggressive Compliance Targets**
  - CPP targets of 45% below baseline by 2030, 80% below baseline by 2040
- **No Community Compliance Investments**

Additional Scenarios Considered:

- **Federal Renewable Gaseous Fuel Support**
  - Renewable energy production tax credit of 30% extended to hydrogen and synthetic gas infrastructure and to biofuel RNG
- **Community-minded Voluntary Programs**
  - Smart Energy program counts for compliance

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Scenario Comparison- Key Results

Scenario	Renewable Supply Penetration (% of Deliveries)			Biofuel RNG Penetration (% of Current Deliveries)			Renewable Supply Portfolio Cost (2020$/Dth)			Total Incremental Cost of CPP Program (Million 2020$/Year)			Community Climate Investments (% of Emissions)			Annual Residential Bill Impact (% Impact of CPP)			Annual Industrial Sales Bill Impact (% Impact of CPP)		
	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050	2025	2035	2050
Base Case	*4%*	*23%*	*72%*	*4%*	*8%*	*14%*	*$12.25*	*$11.85*	*$11.77*	*$142*	*$256*	*$242*	*6%*	*20%*	*0%*	*9%*	*9%*	*-2%*	*22%*	*35%*	*39%*
Restricted RNG	4%	23%	72%	4%	9%	11%	$18.75	$18.26	$16.90	$142	$317	$324	6%	20%	0%	13%	19%	9%	30%	59%	68%
Customer Decline	4%	17%	65%	4%	9%	15%	$12.25	$11.93	$11.59	$118	$181	$186	6%	20%	0%	8%	15%	18%	18%	27%	37%
Aggressive Timeline	4%	47%	65%	4%	16%	20%	$12.25	$13.15	$11.74	$168	$493	$360	13%	20%	20%	10%	23%	2%	27%	73%	58%
No CCIs	10%	36%	72%	10%	15%	18%	$12.25	$12.64	$12.89	$167	$313	$296	0%	0%	0%	11%	13%	3%	26%	45%	51%
Federal RNG Support	4%	23%	72%	4%	8%	14%	$8.58	$8.76	$8.80	$142	$239	$160	6%	20%	0%	7%	4%	-9%	18%	26%	17%
Voluntary Community Support	4%	16%	48%	4%	8%	9%	$12.25	$11.85	$11.25	$124	$214	$160	2%	20%	20%	8%	6%	-6%	19%	30%	25%

Appendix

Restricted RNG Scenario- Key Results

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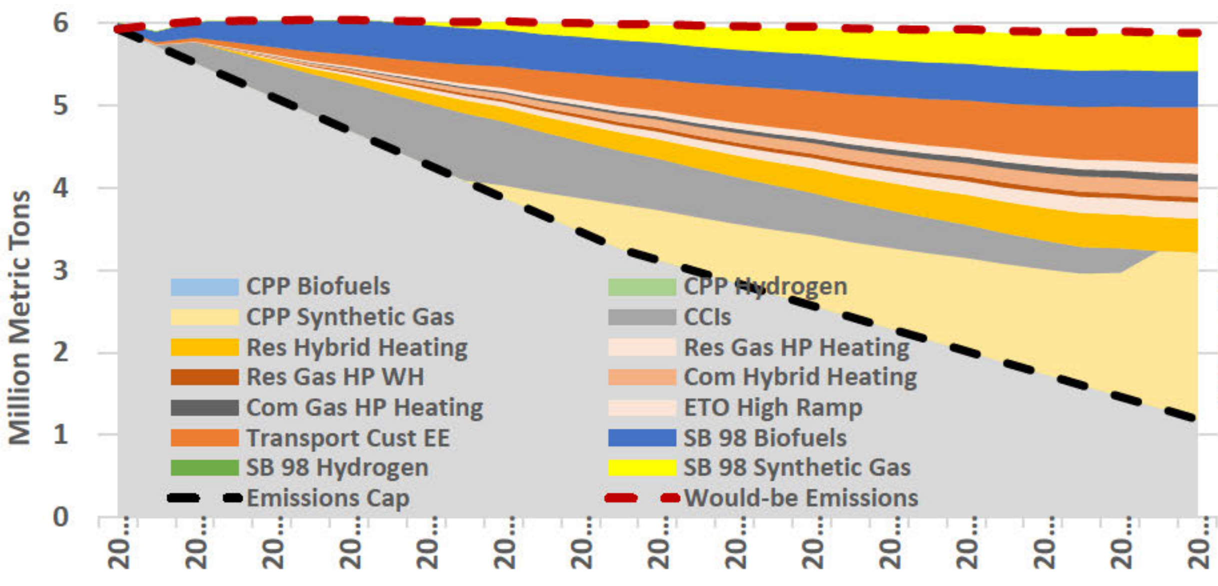
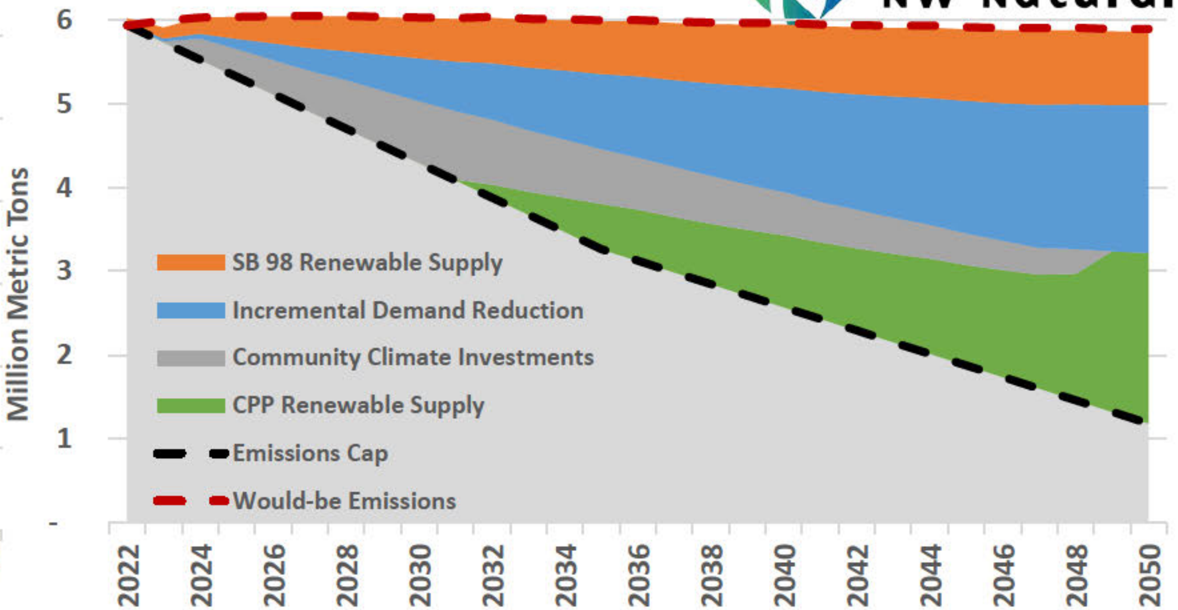
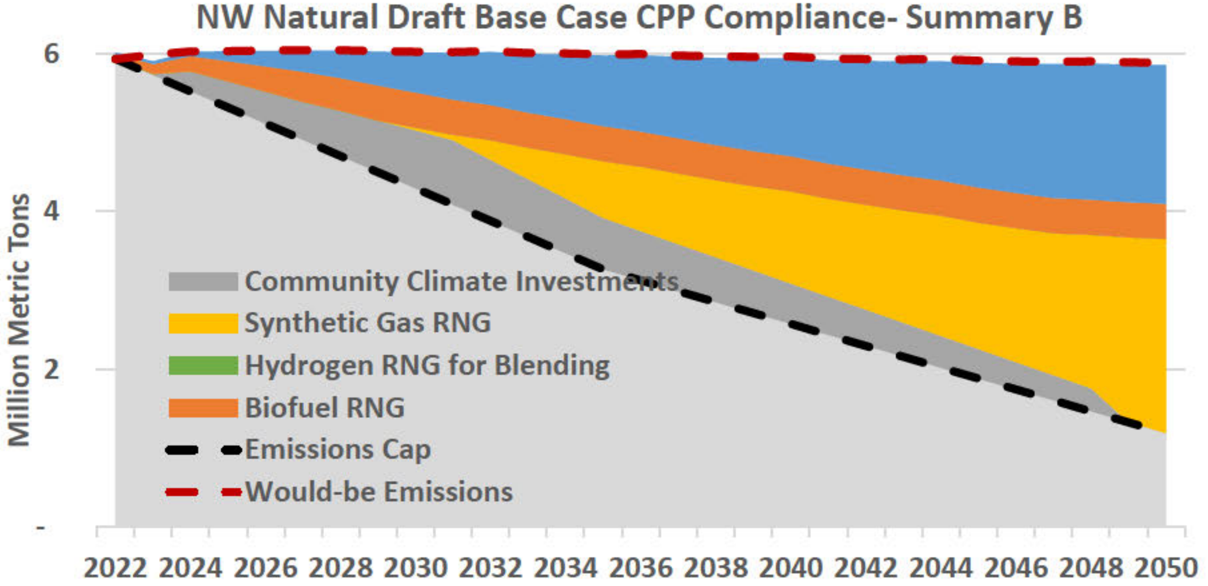
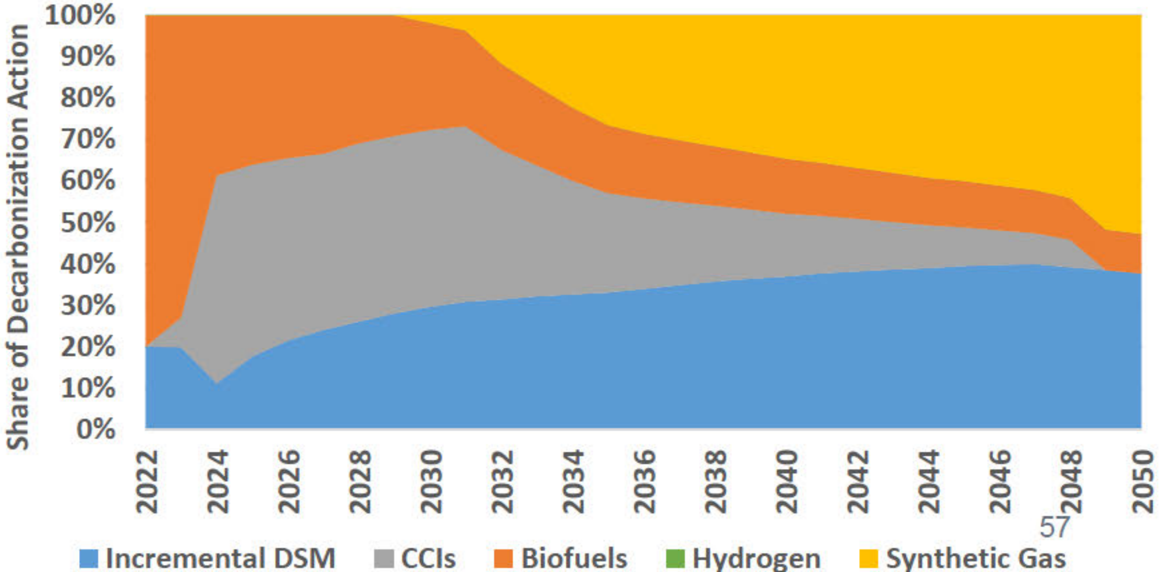
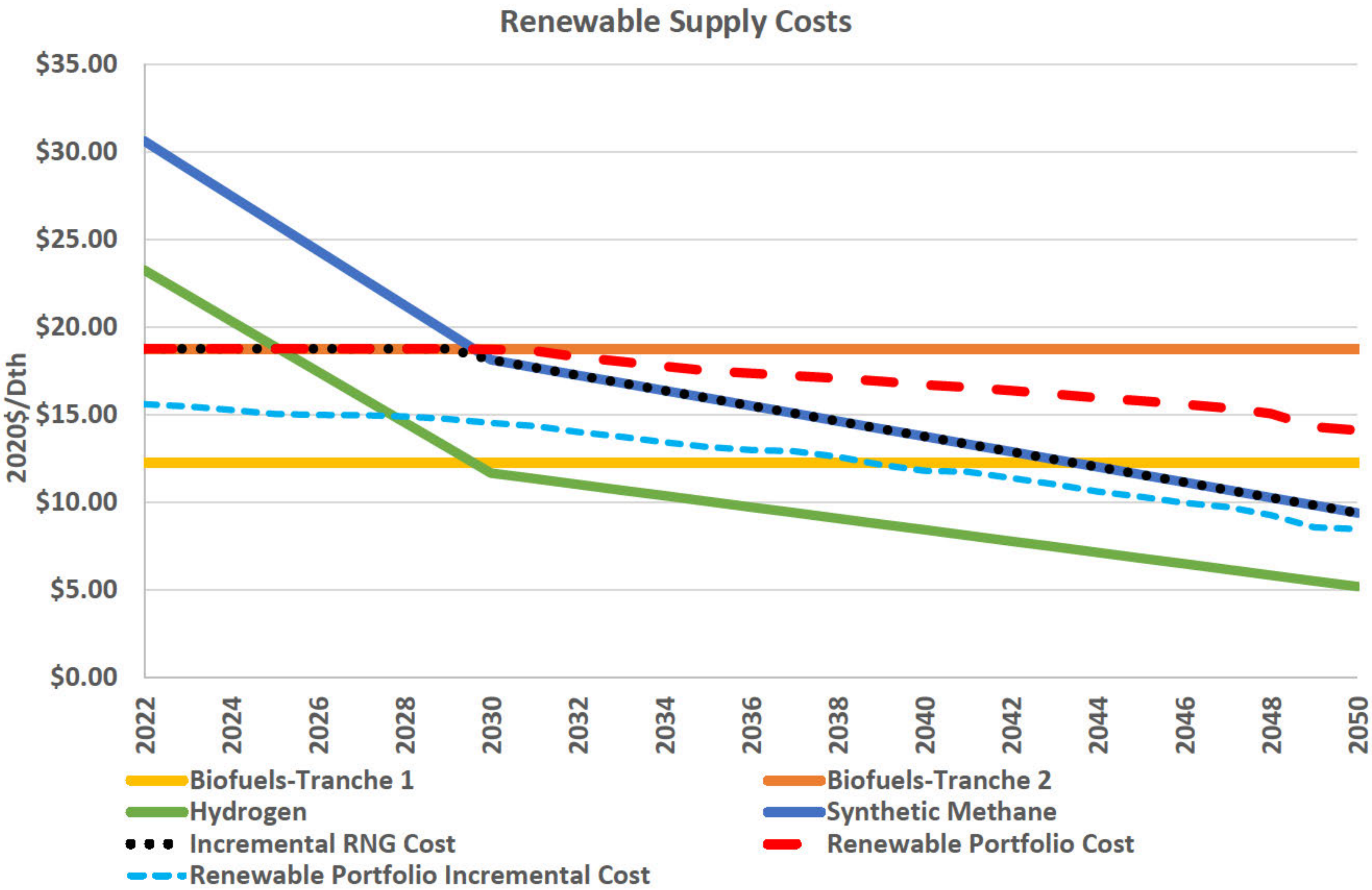




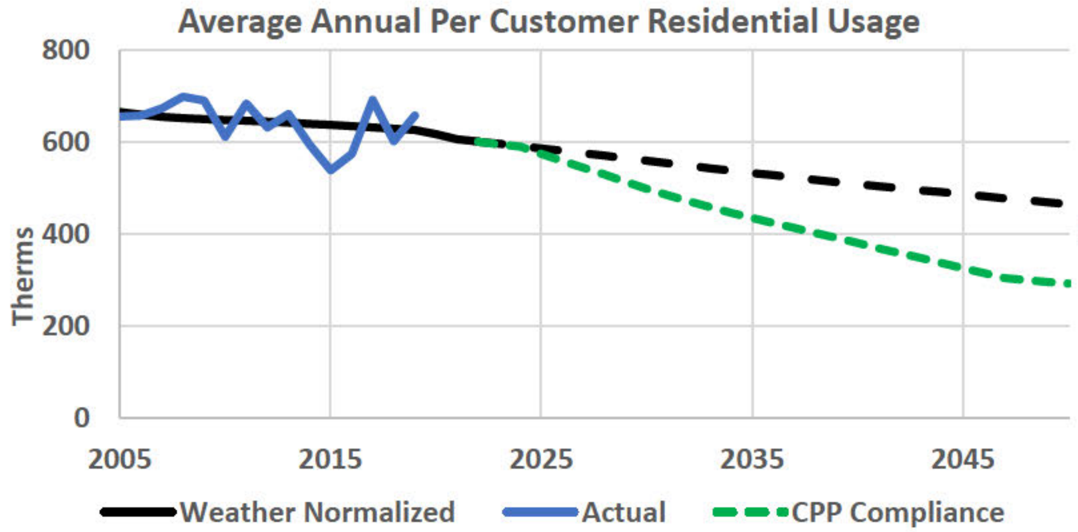


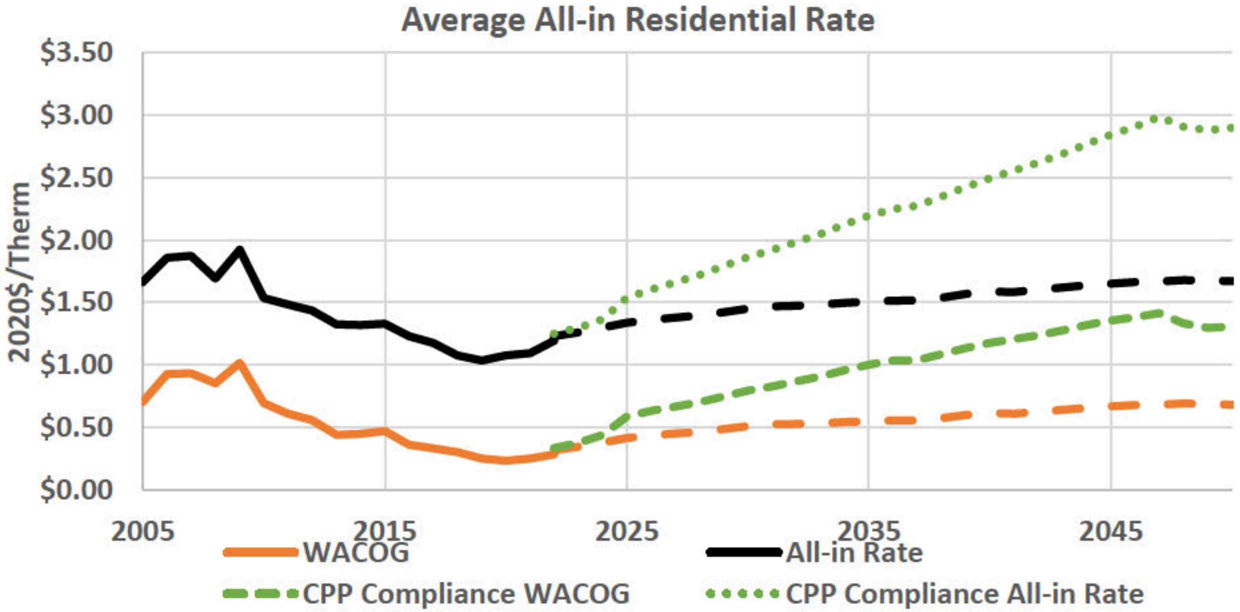


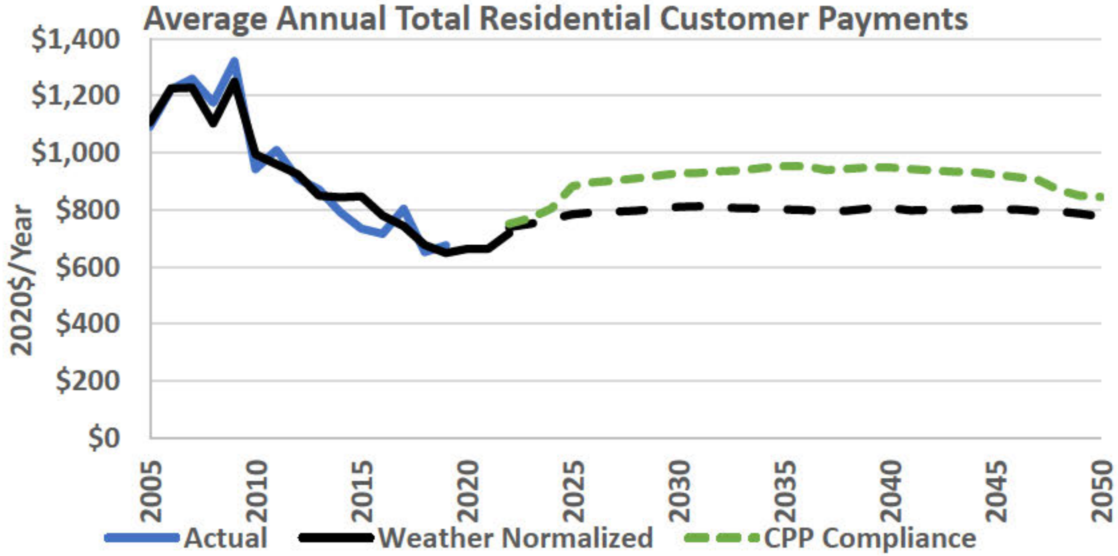
Restricted RNG Scenario- Renewable Supply Results

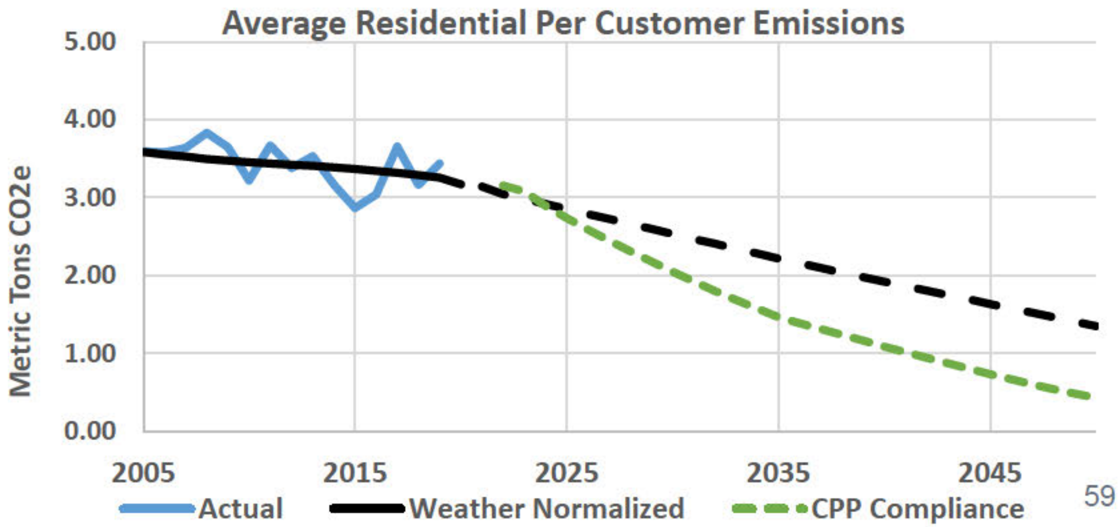


Restricted RNG Scenario- Residential Results

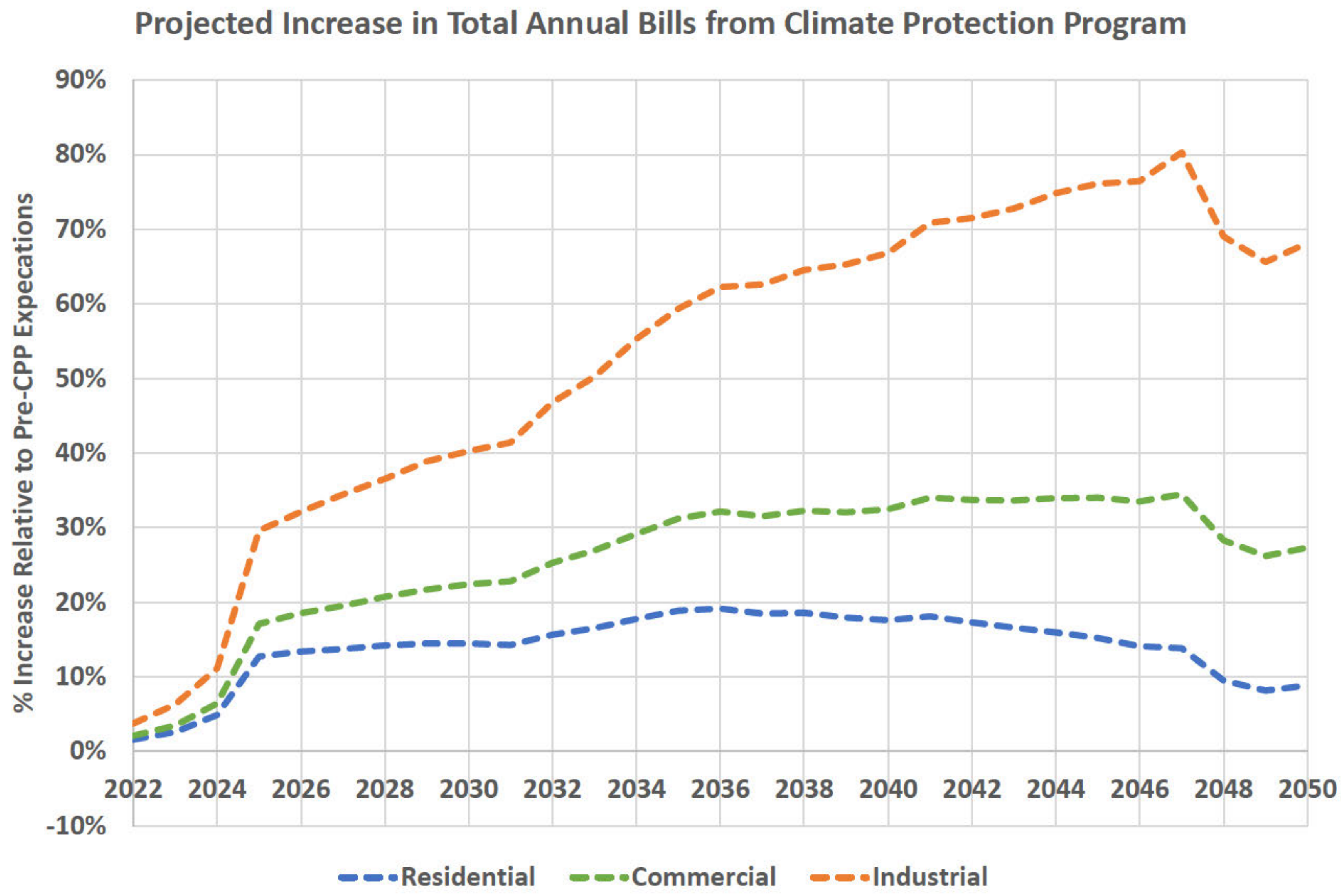






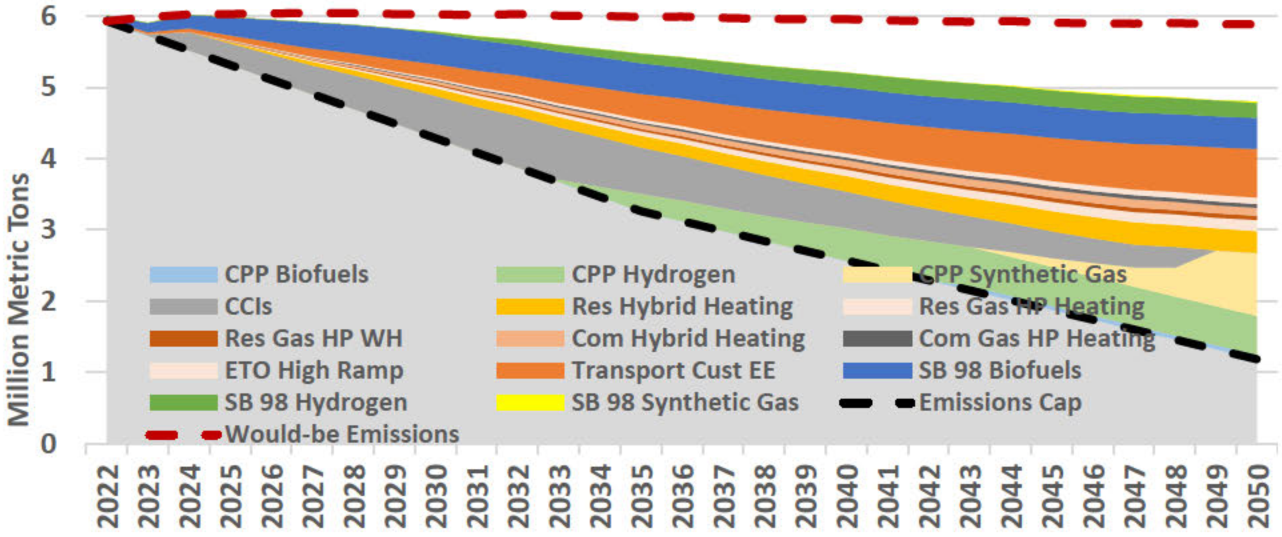


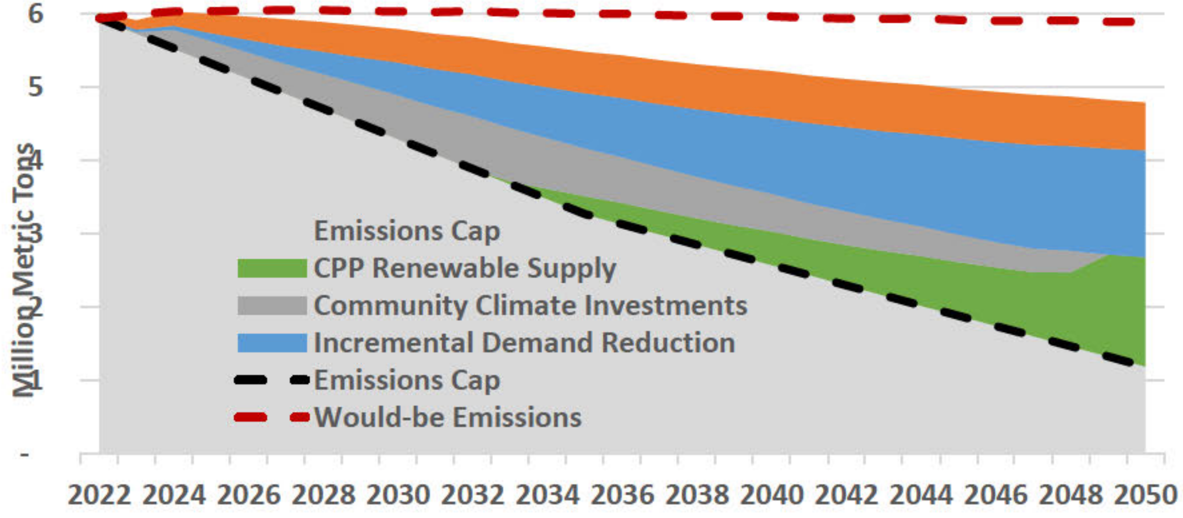
Restricted RNG Scenario- Bill Impacts

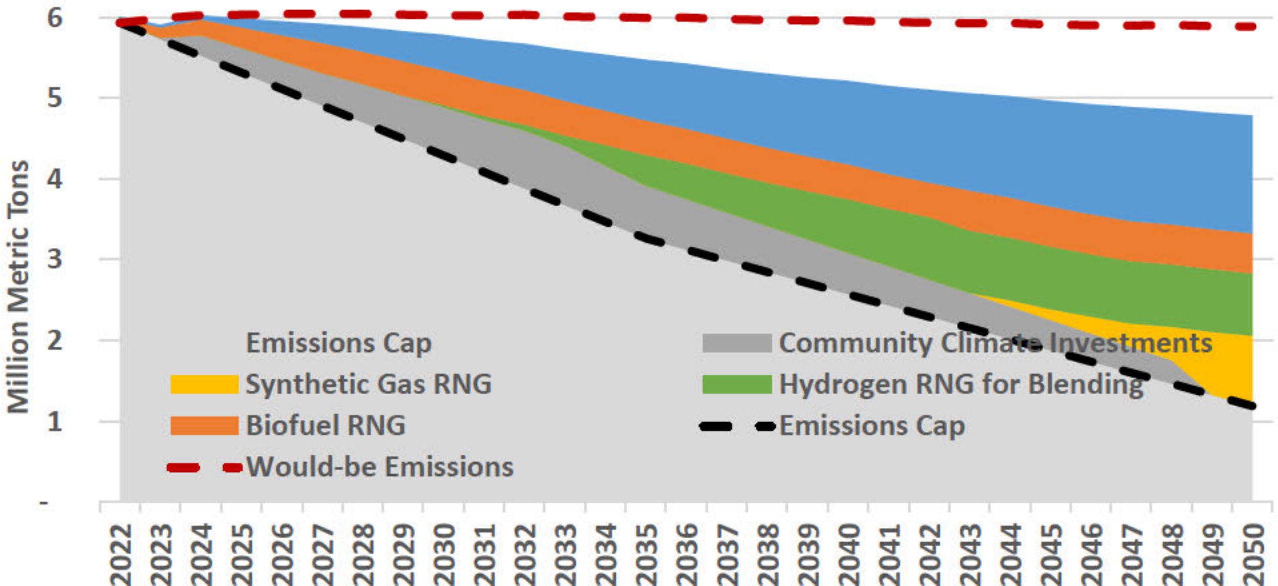


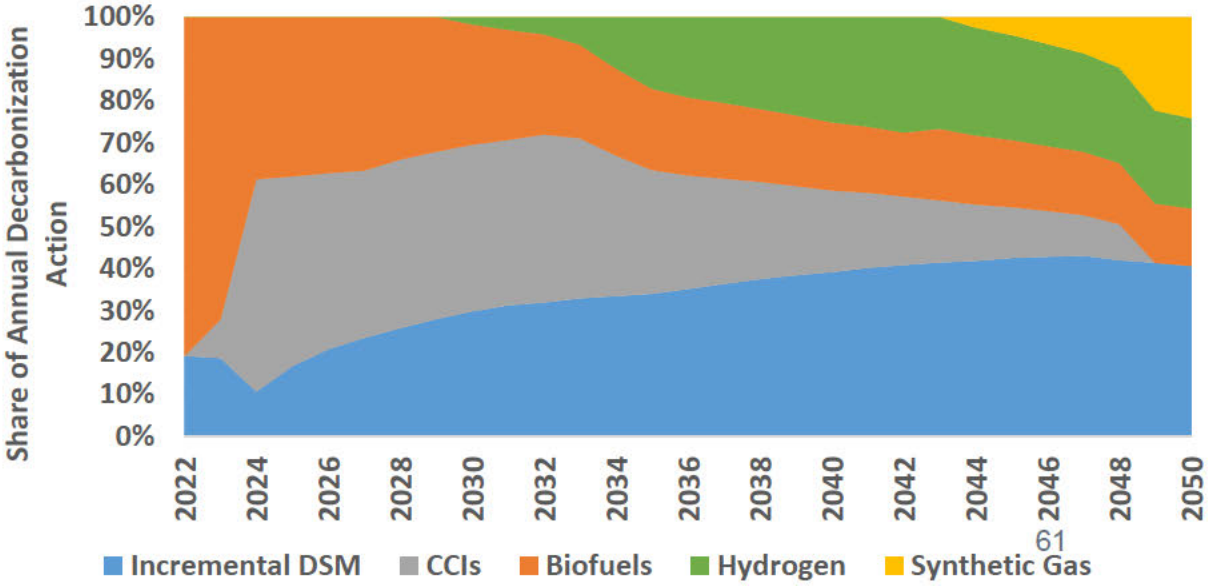
	Residential	Commercial	Industrial
2022	2%	2%	4%
2025	13%	17%	30%
2030	14%	22%	40%
2035	19%	31%	59%
2040	18%	32%	67%
2050	9%	27%	68%

Customer Decline Scenario- Key Results

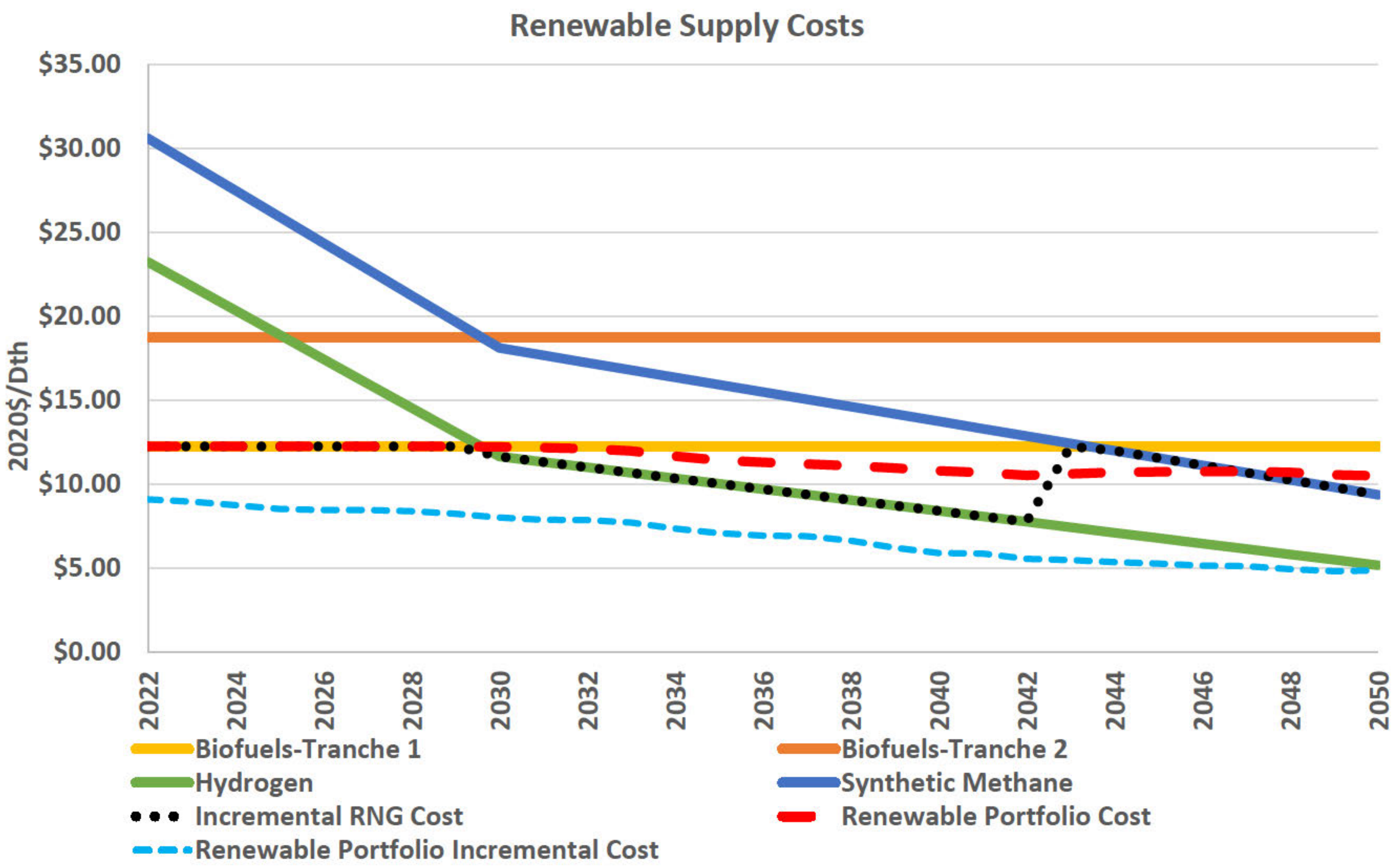




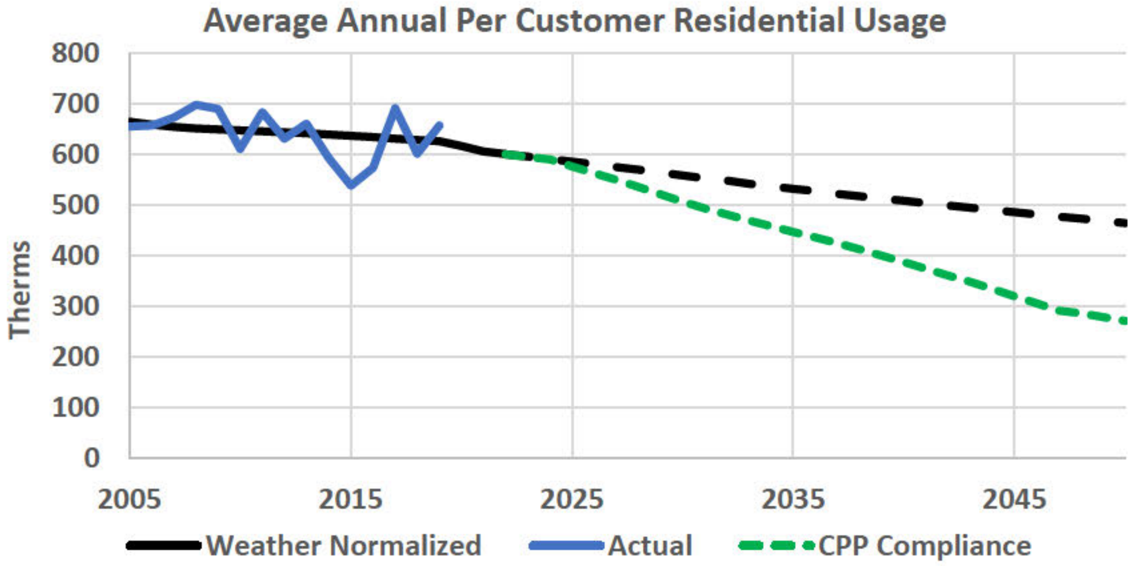


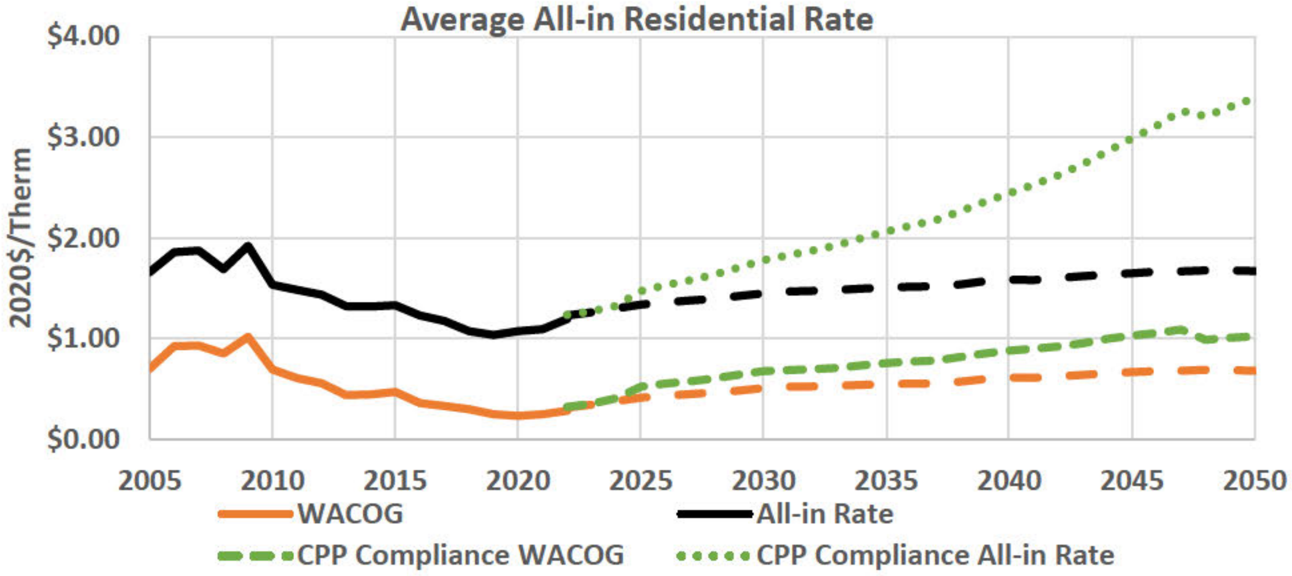


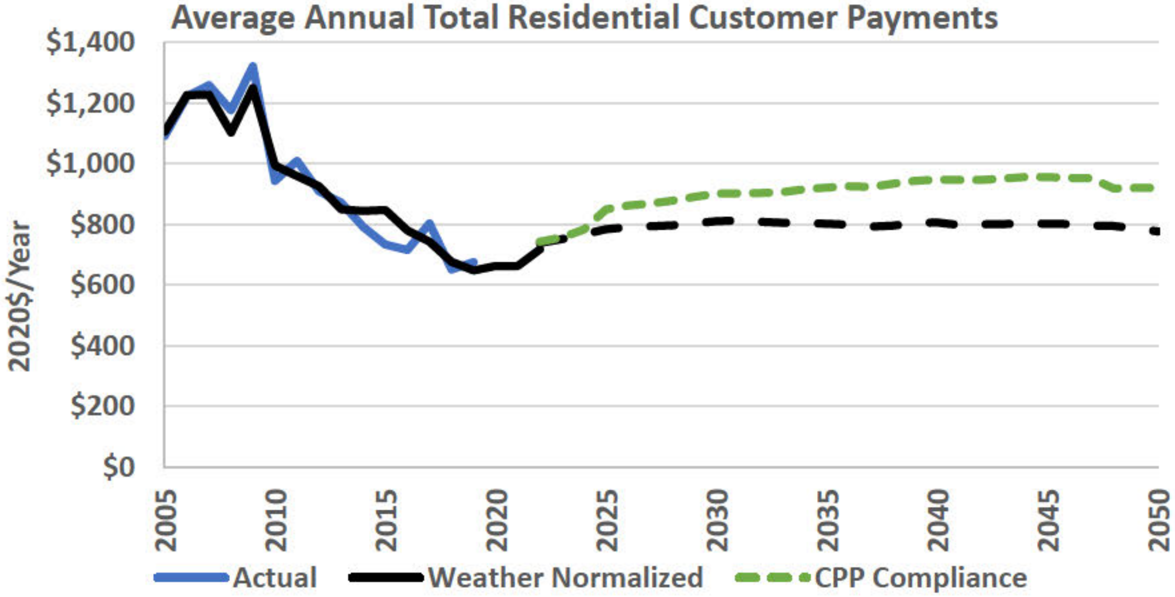
Customer Decline Scenario- Renewable Supply Results

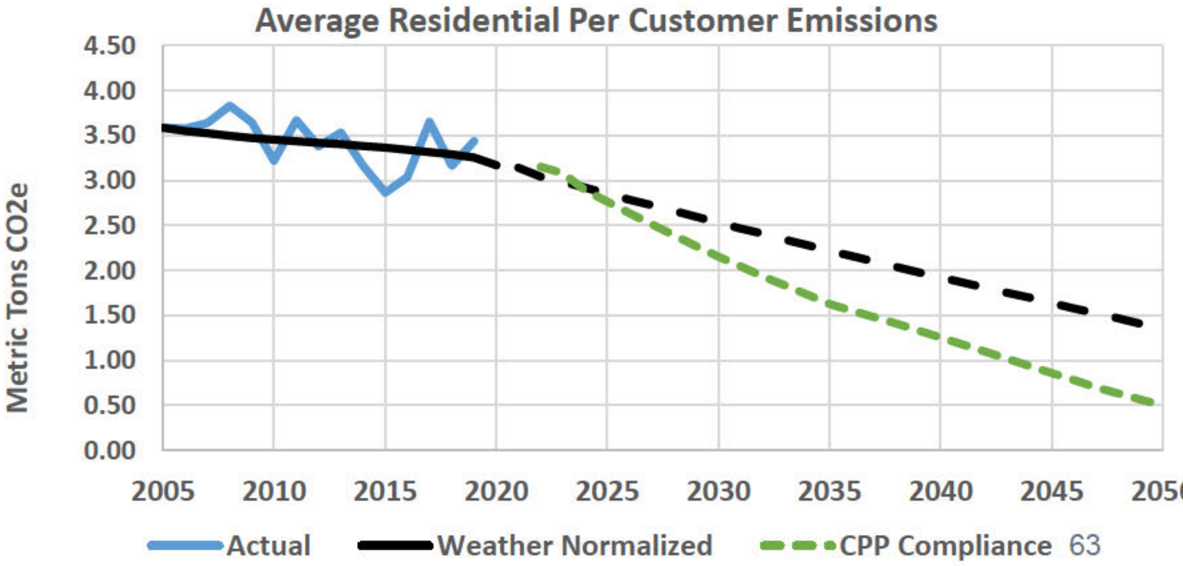


Customer Decline Scenario- Residential Results

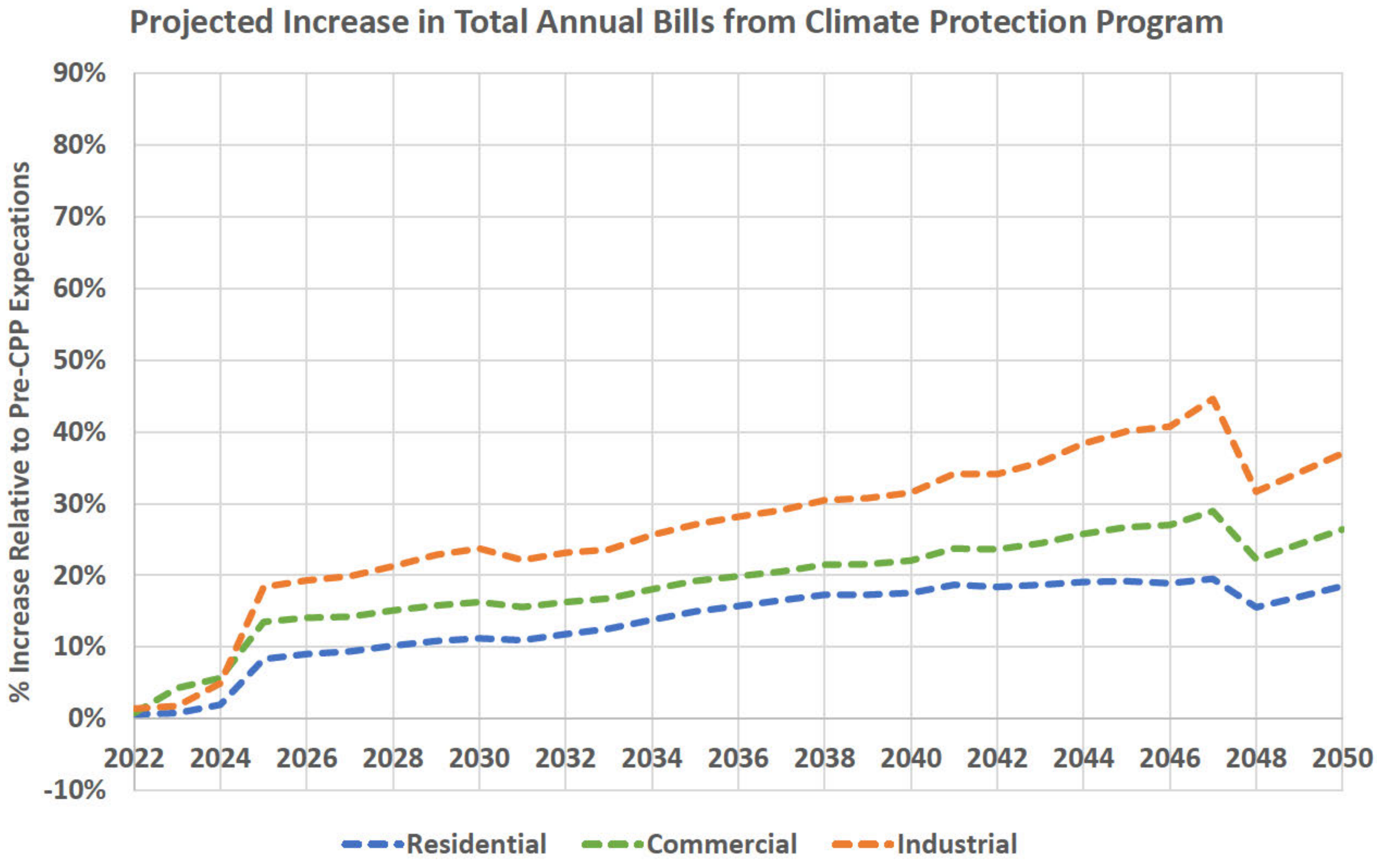






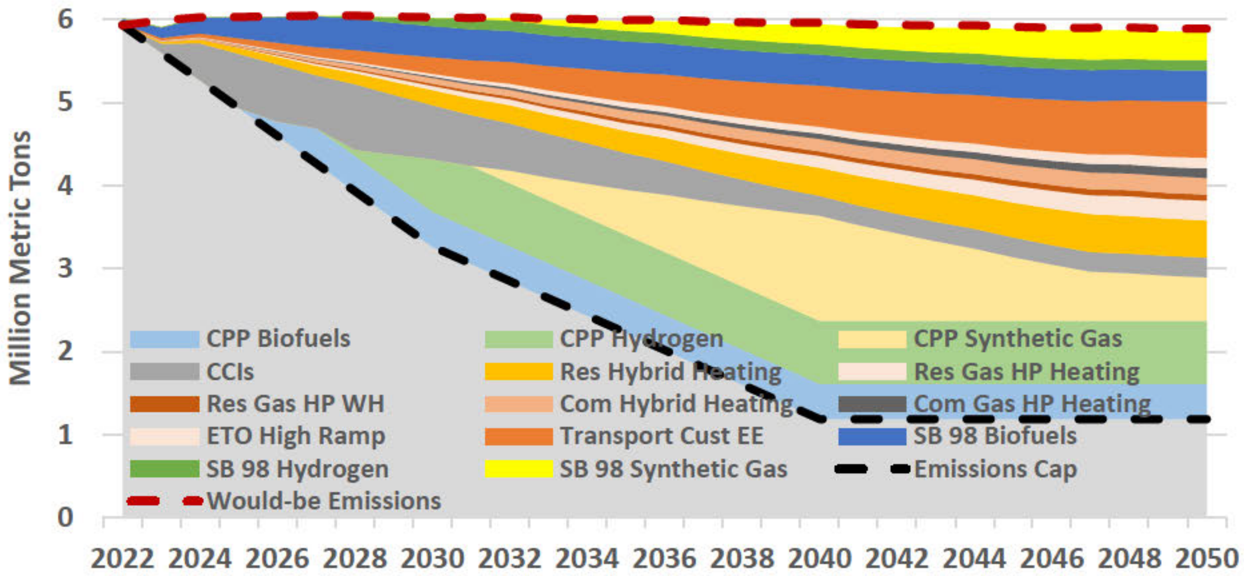


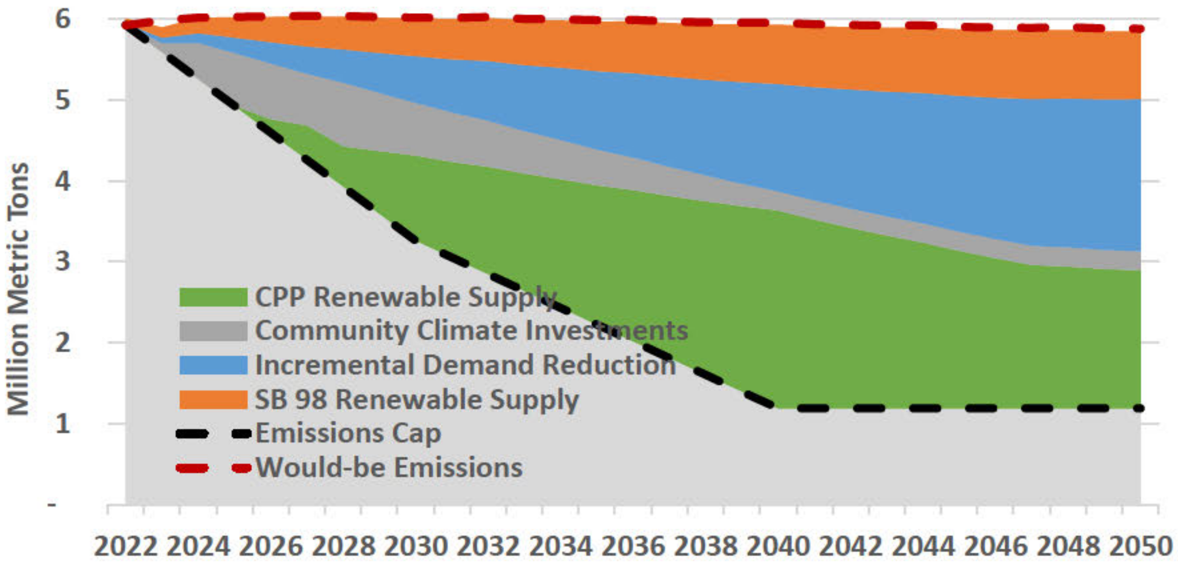
Customer Decline Scenario- Bill Impacts

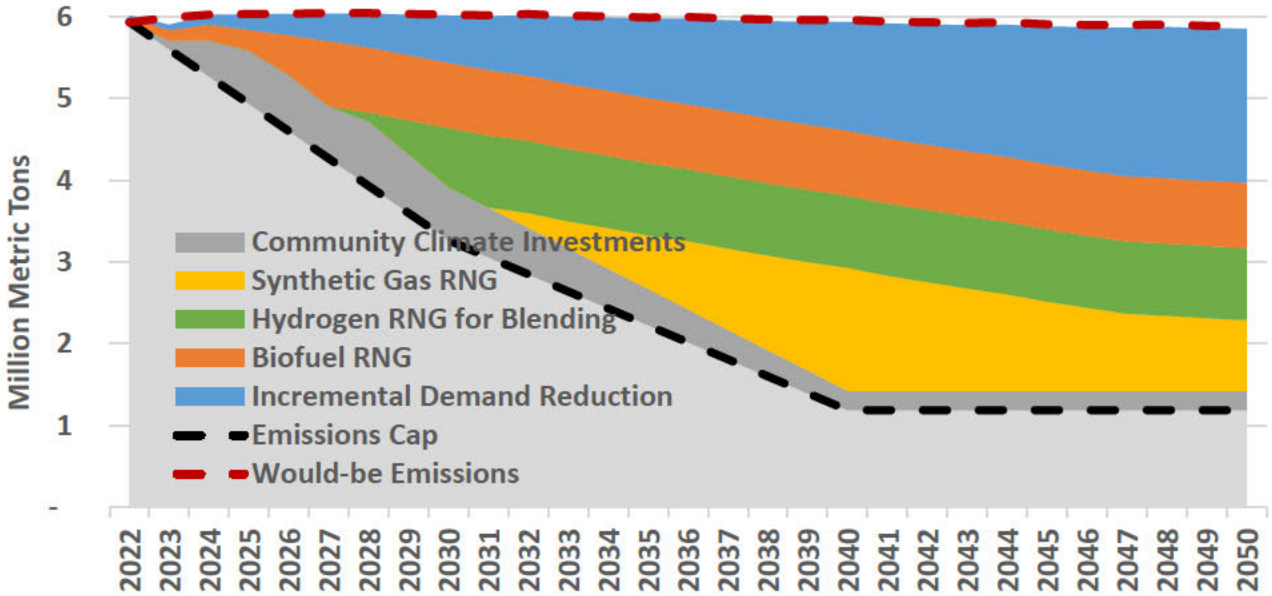


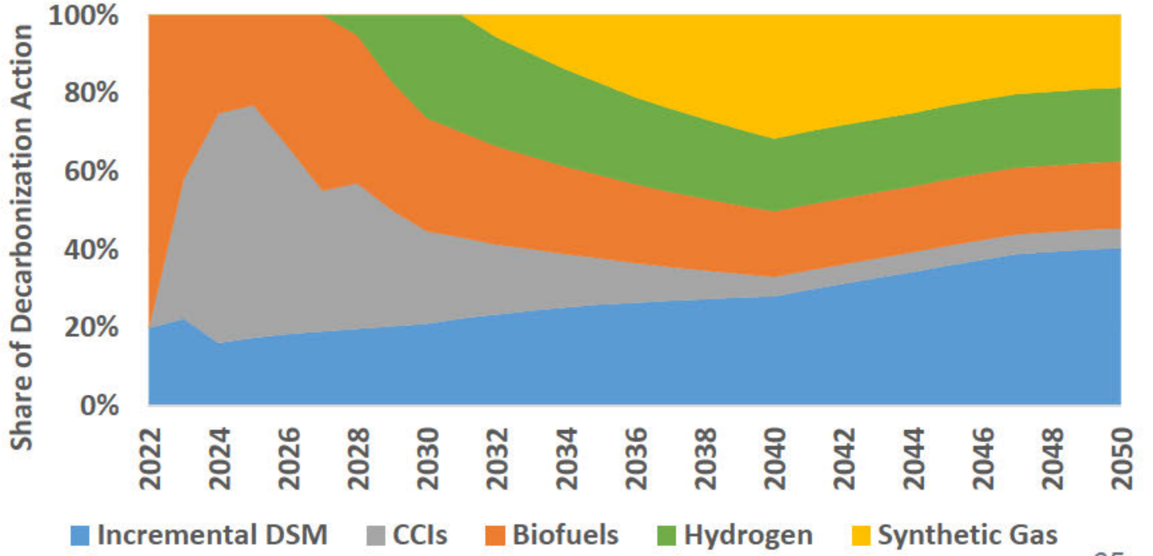
	Residential	Commercial	Industrial
2022	1%	1%	1%
2025	8%	14%	18%
2030	11%	16%	24%
2035	15%	19%	27%
2040	18%	22%	32%
2050	18%	26%	37%

Aggressive Timeline Scenario- Key Results

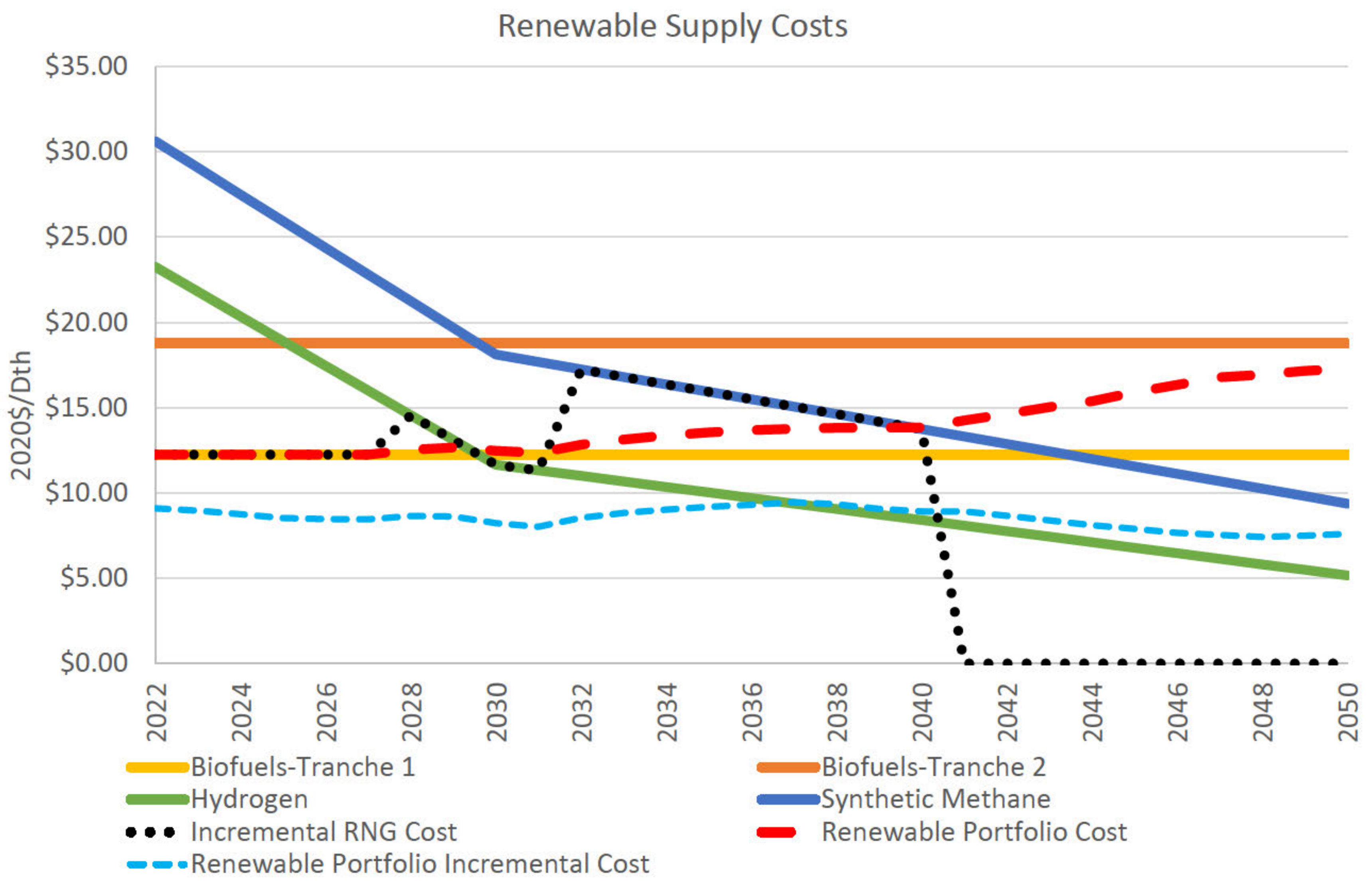




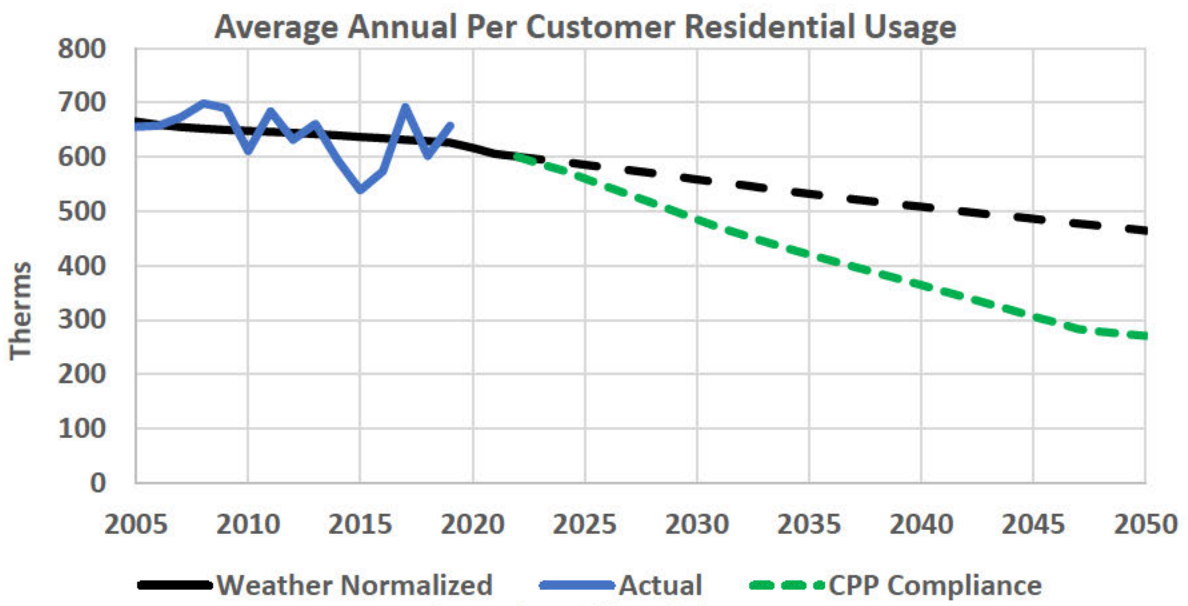


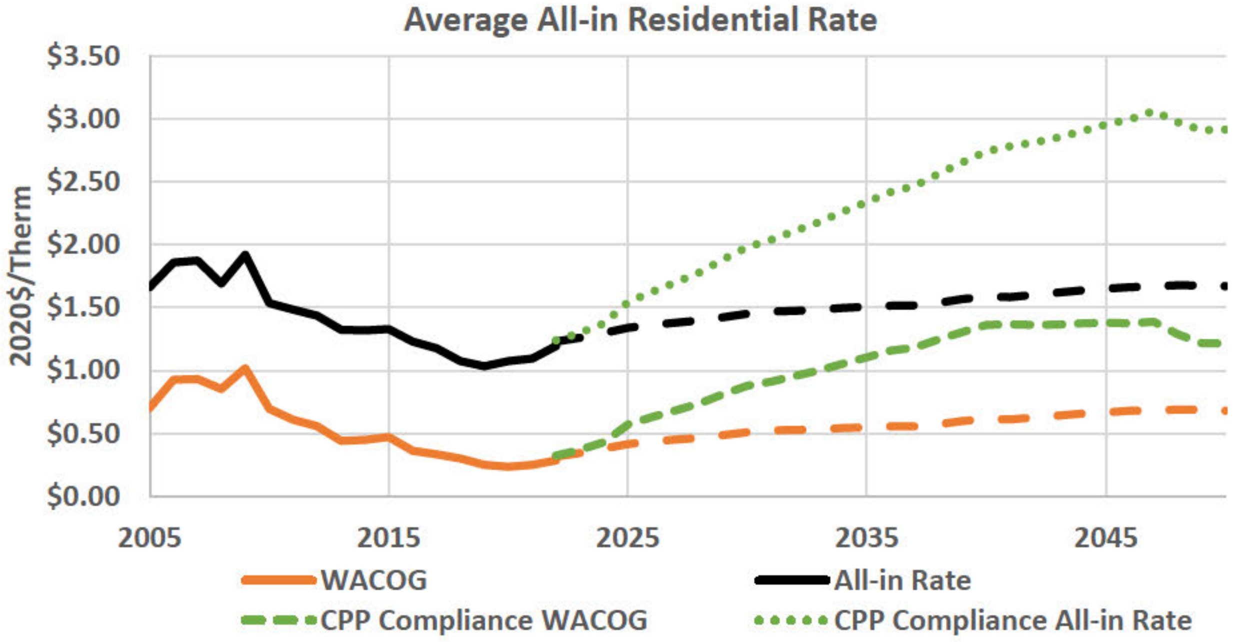


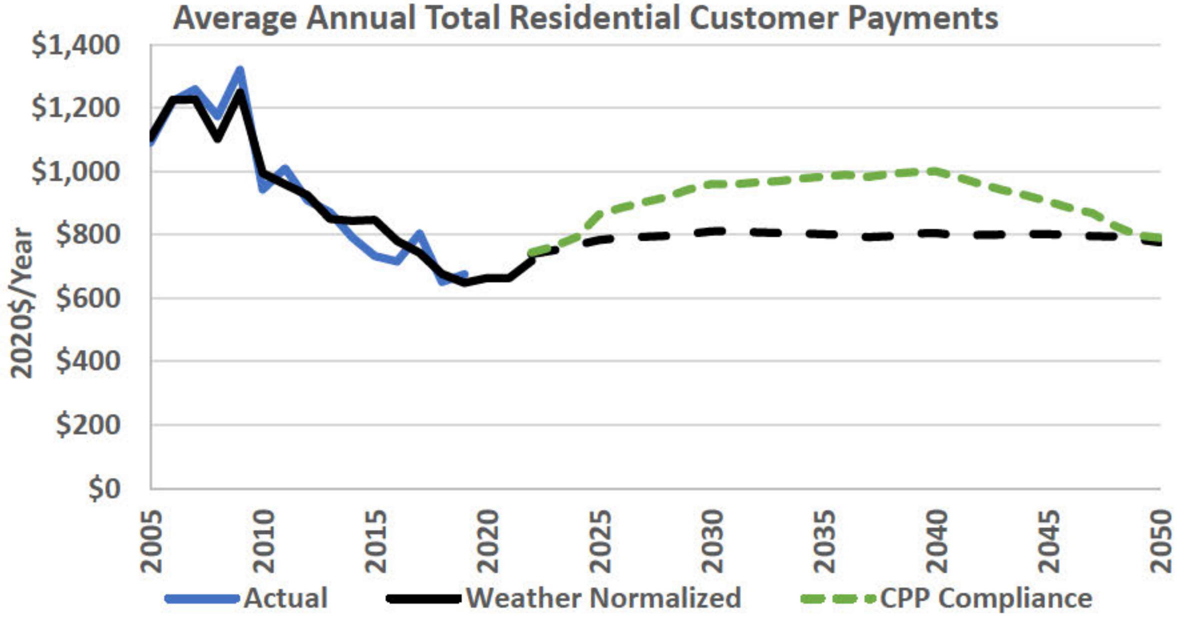
Aggressive Timeline Scenario- Renewable Supply Results

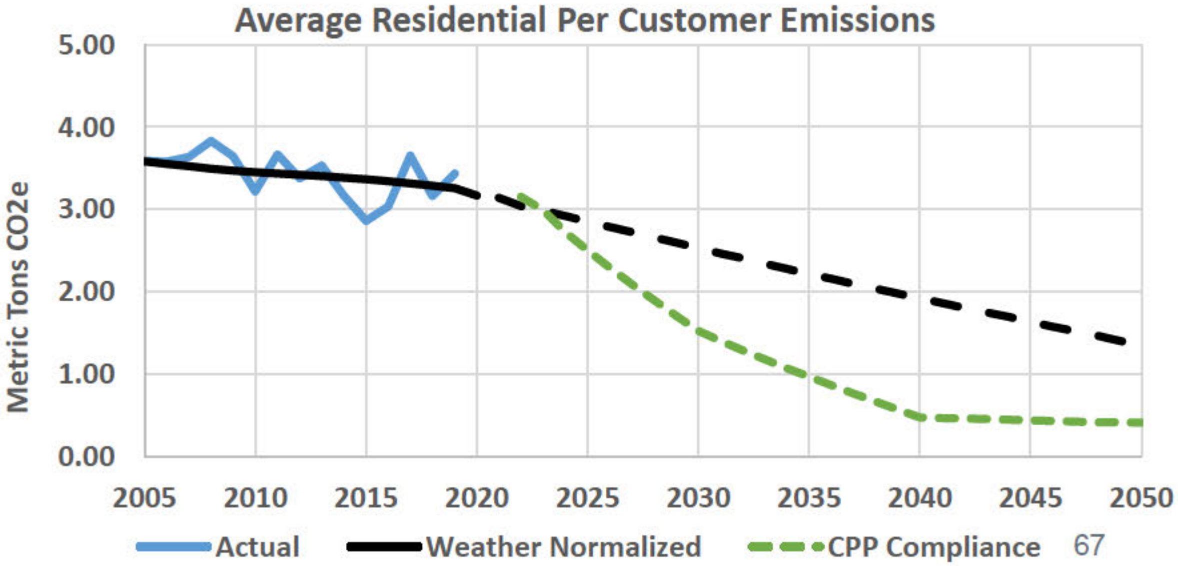


Aggressive Timeline Scenario- Residential Results

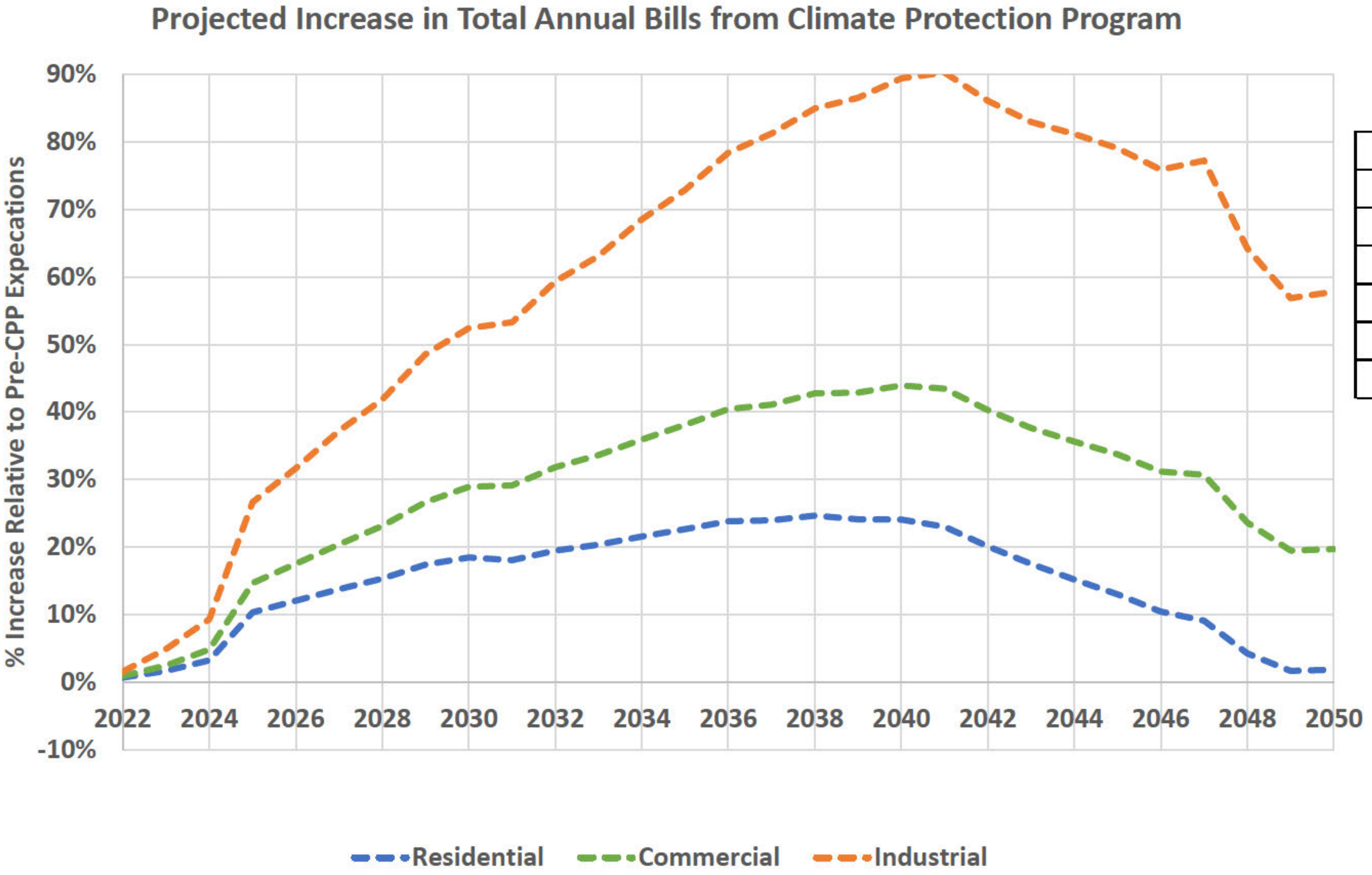






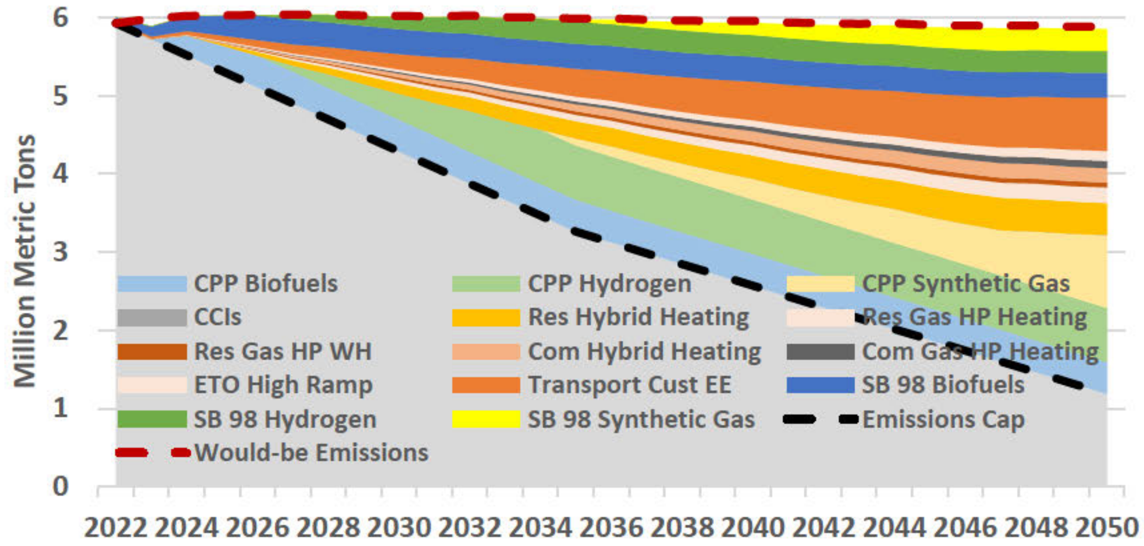


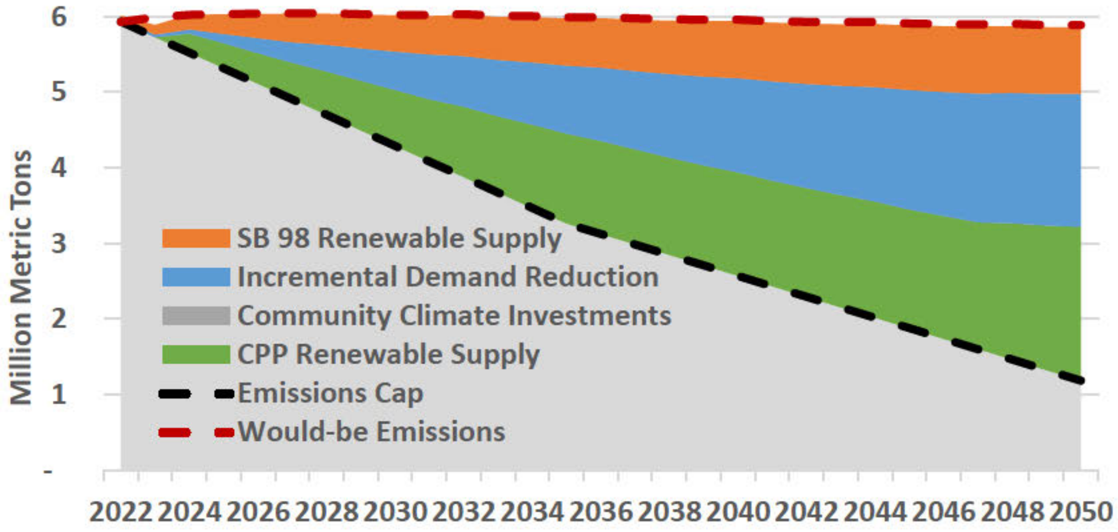
Aggressive Timeline Scenario- Bill Impacts

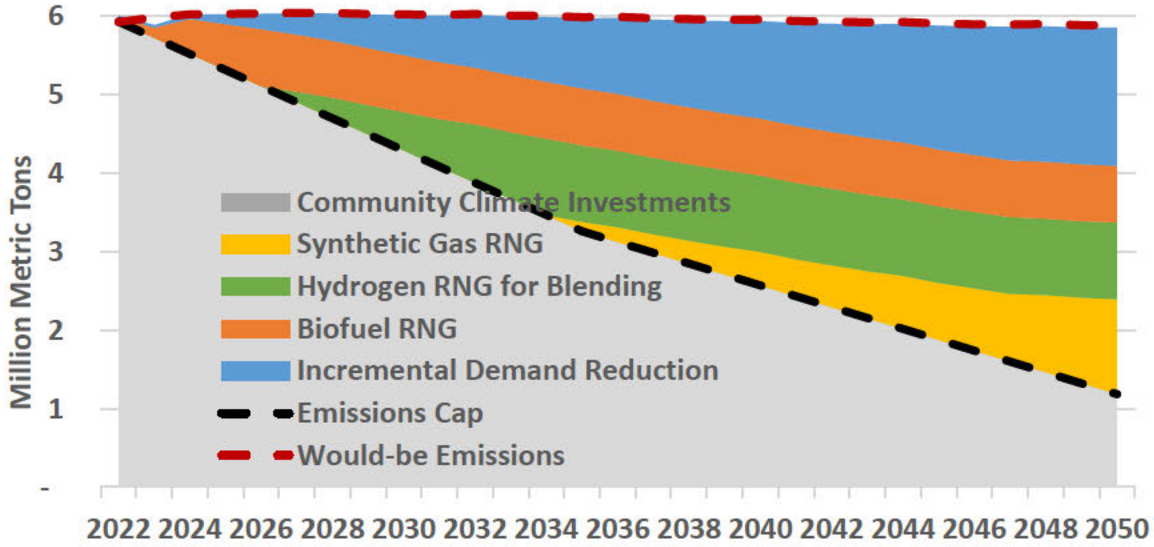


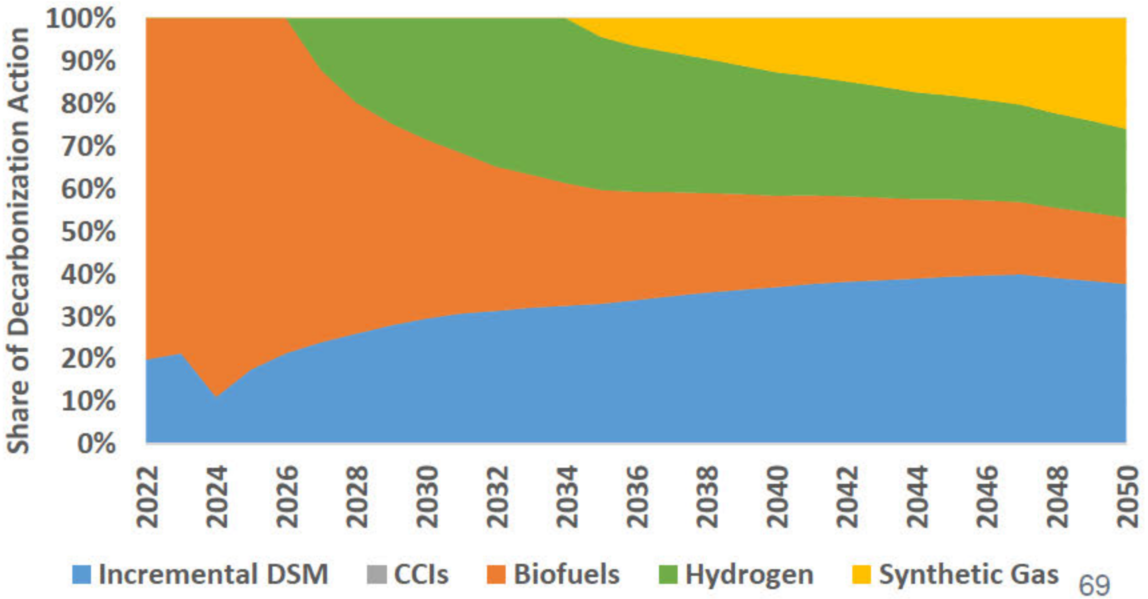
	Residential	Commercial	Industrial
2022	1%	1%	2%
2025	10%	15%	27%
2030	18%	29%	52%
2035	23%	38%	73%
2040	24%	44%	89%
2050	2%	20%	58%

No CCI Scenario- Key Results

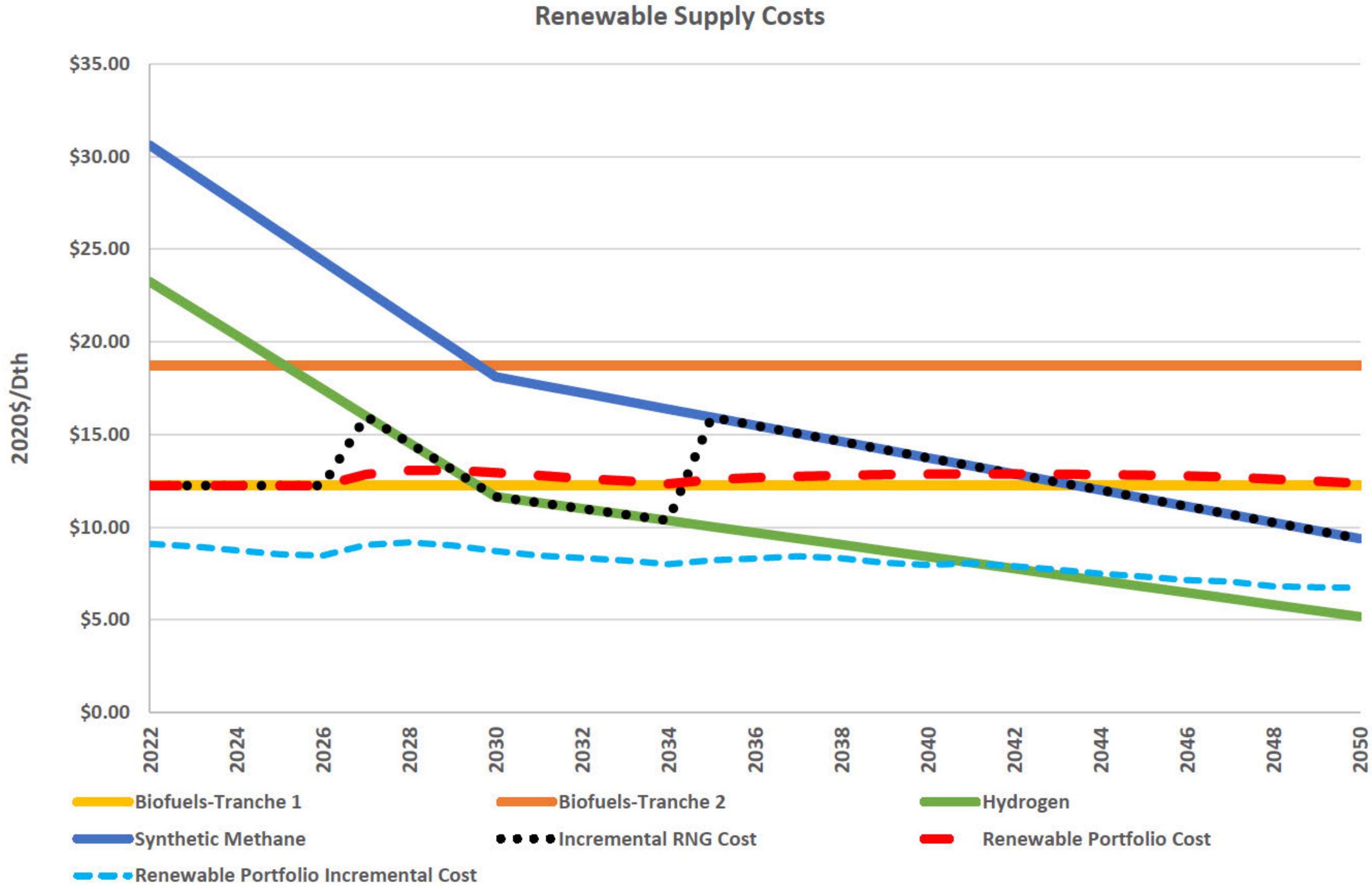




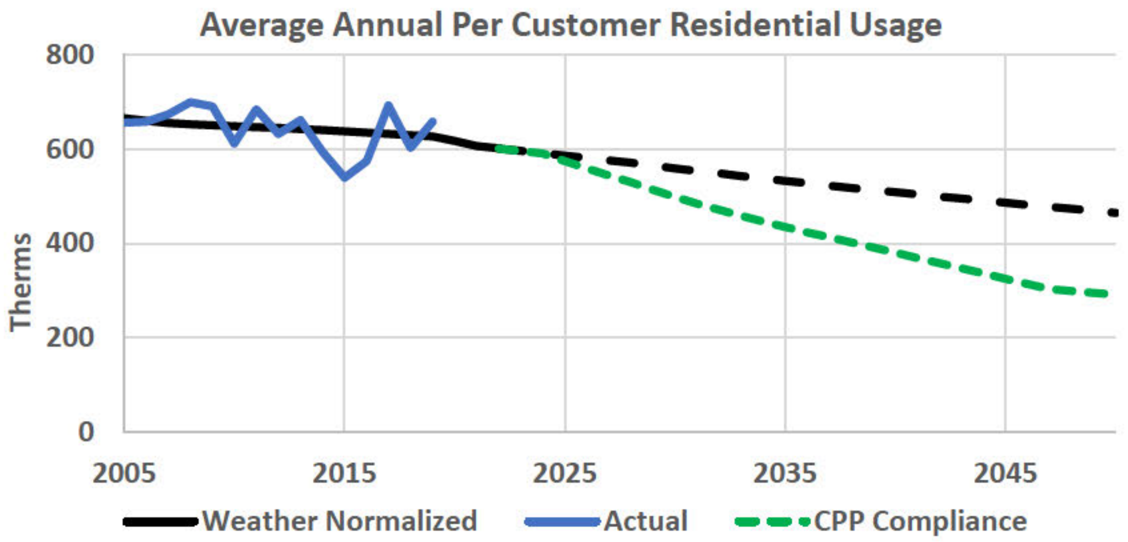


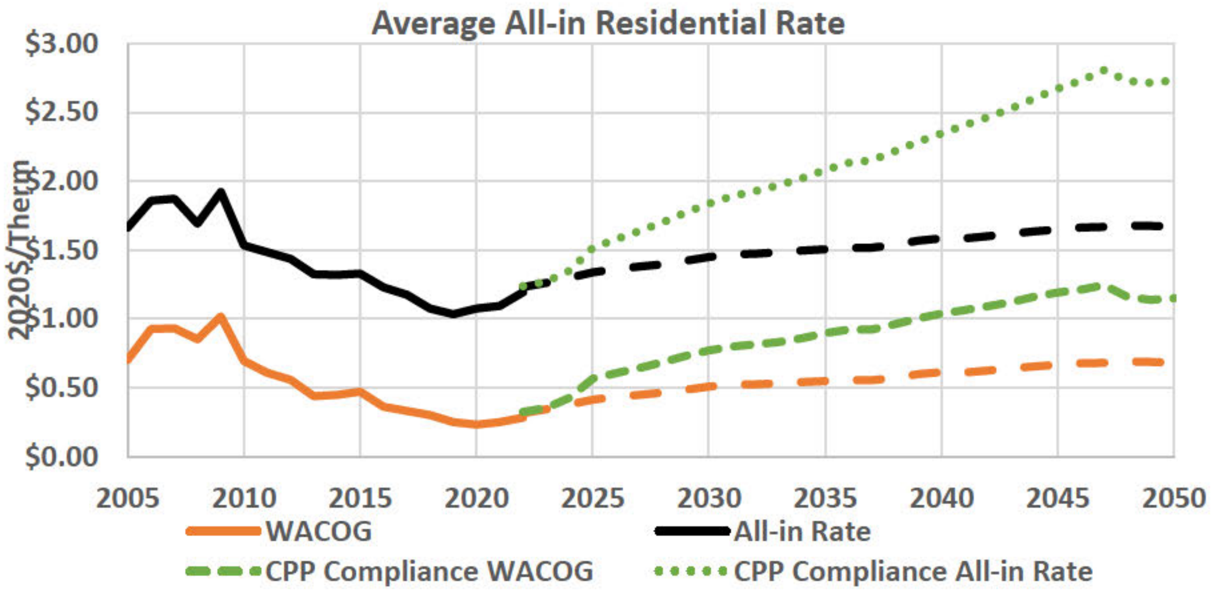


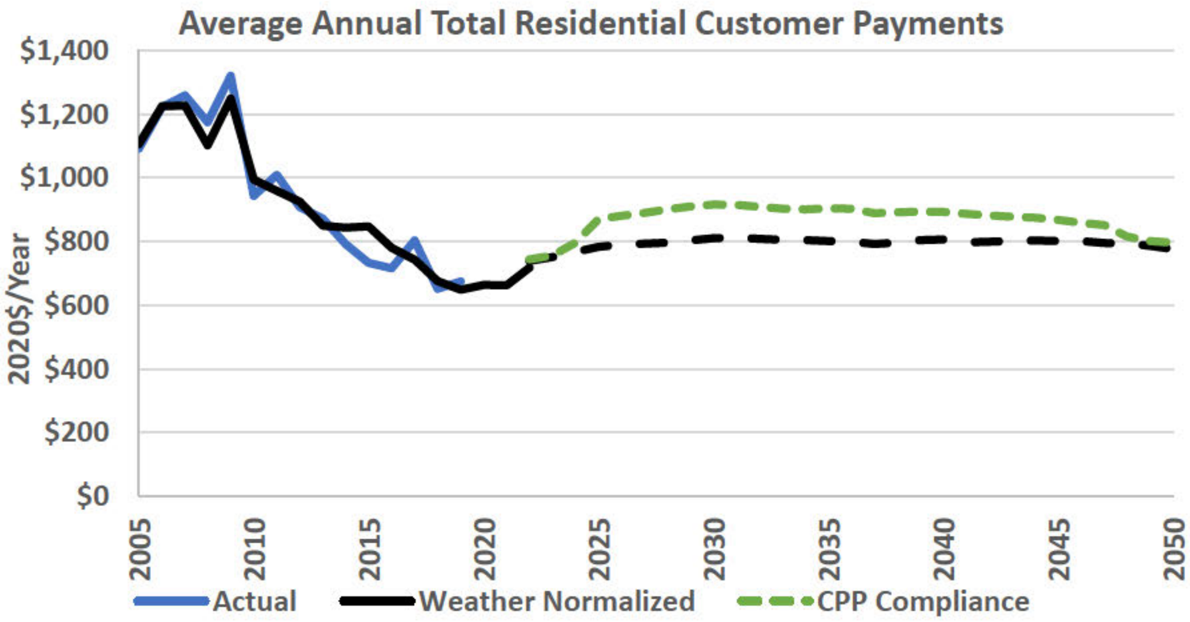
No CCI Scenario – Renewable Supply Results

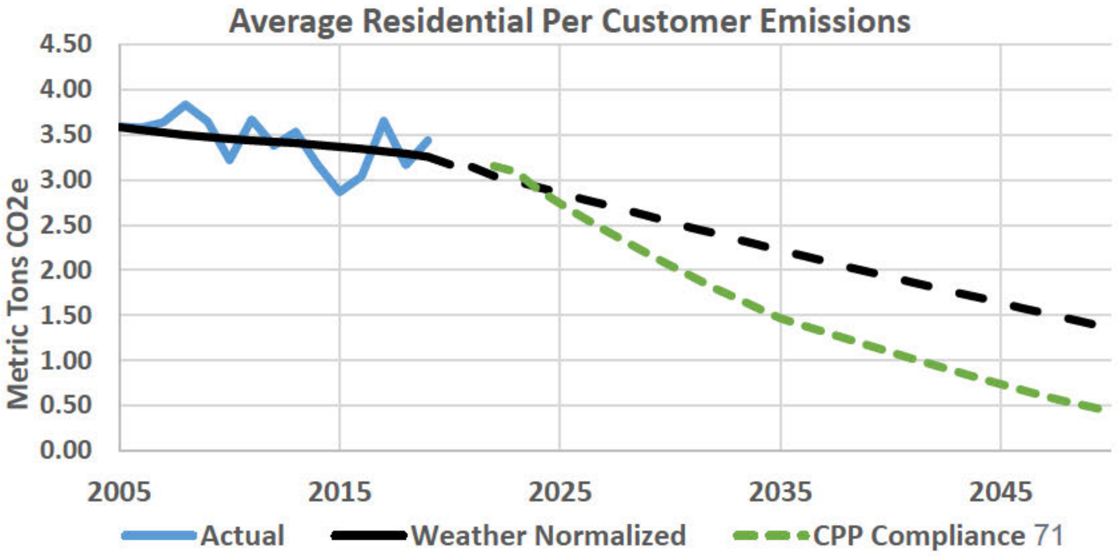


No CCI Scenario- Residential Results

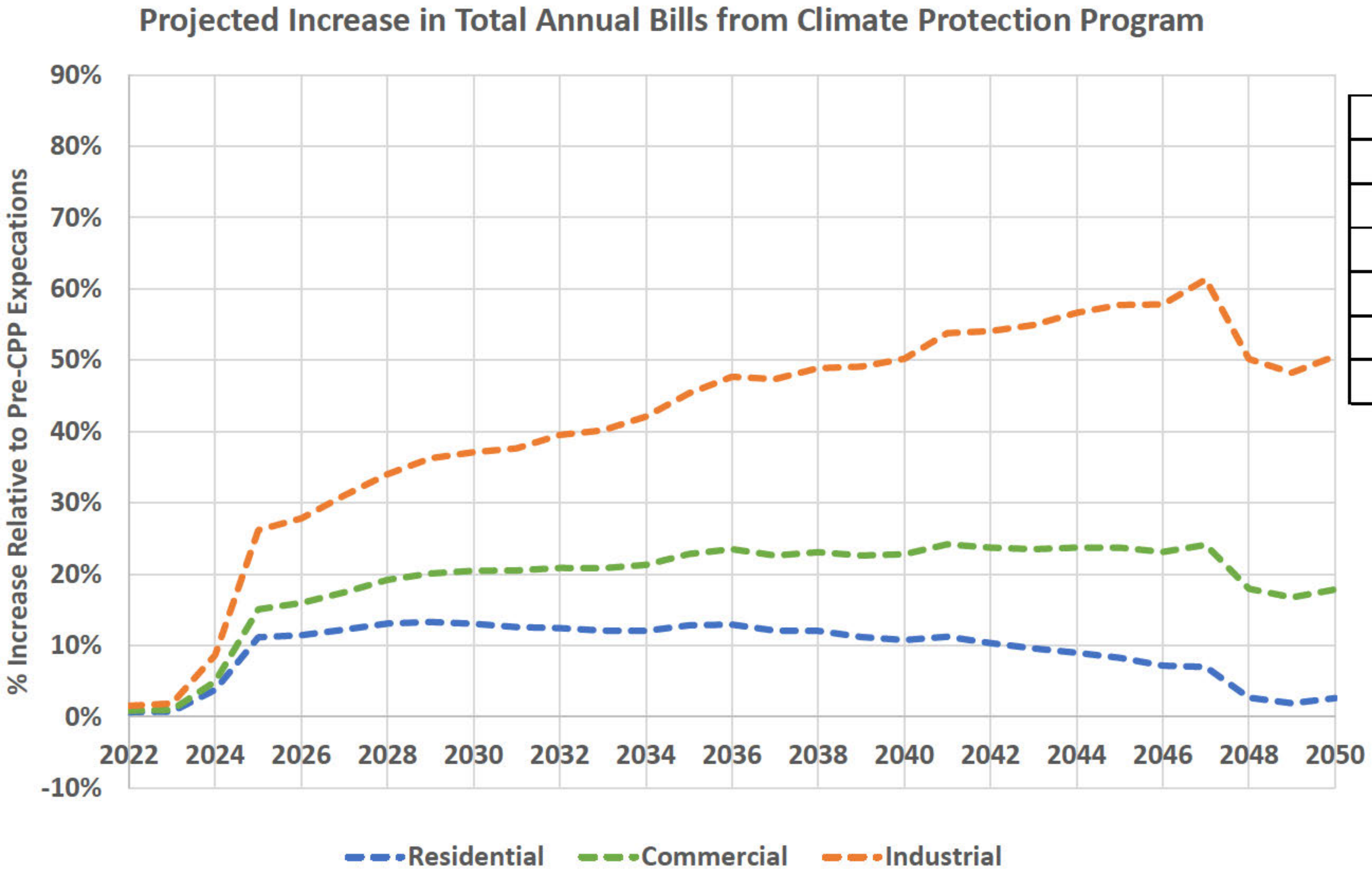








No CCI Scenario- Bill Impacts



	Residential	Commercial	Industrial
2022	1%	1%	2%
2025	11%	15%	26%
2030	13%	20%	37%
2035	13%	23%	45%
2040	11%	23%	50%
2050	3%	18%	51%

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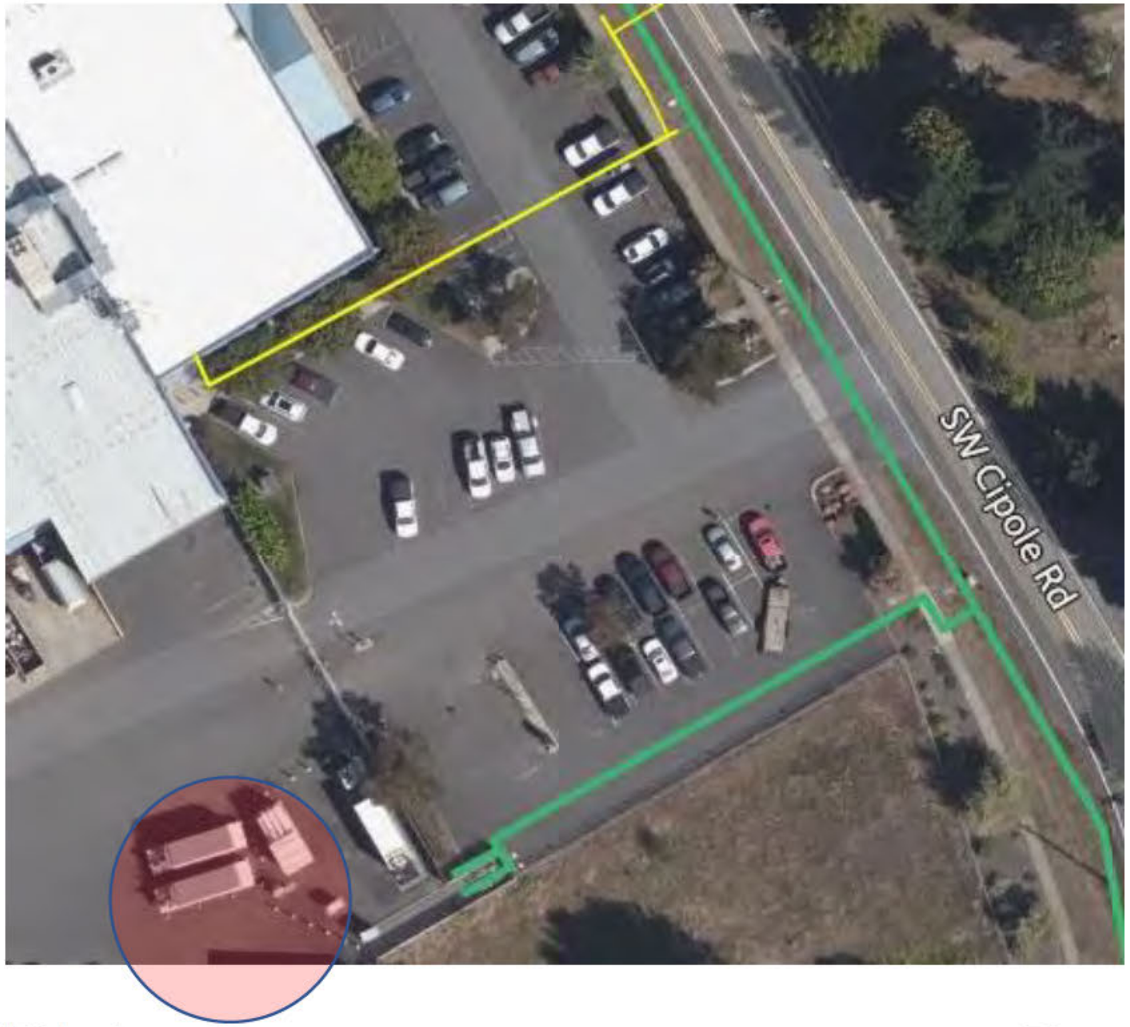
Hydrogen Next Steps

Blending Trials

- 5-20%vol hydrogen blend testing at Sherwood
- Hydrogen sourced (gray)
- Blending solution sourced
- Need to identify design & construction pathway
- Goal is to start blending by Q4/2021

Exploring System Readiness Audit



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Safety

- At lower blends, characteristics of the gas are largely unchanged
  - Odorants
  - Upper and lower flammability limits
  - Leaks
- Hawaii Gas has 12% hydrogen blend with natural gas equipment
- Town gas has been used for decades – approx. 50% hydrogen
- 1,600 miles of hydrogen piping exists in the US today

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Investigating Blue Hydrogen

Carbon Sequestration

- Investigating DOGAMI view of permitting, policies
- Black & Veatch high-level view of blue
  - Technologies
  - OPEX/CAPEX
  - Cost of delivered hydrogen (including 45Q)
  - Overall opportunity

Blue hydrogen looks very attractive

- NW Natural has a competitive advantage through its Mist work
- Low cost
- Low carbon intensity (2kgCO2(e)/kgH2 or less)
- Existing technology, significant storage in saline formations (400-5,500 yrs.)
- Possible mechanism for rapid generation of thermal credits
- New business development opportunities through gathering and/or sequestration of carbon for high-emission industries

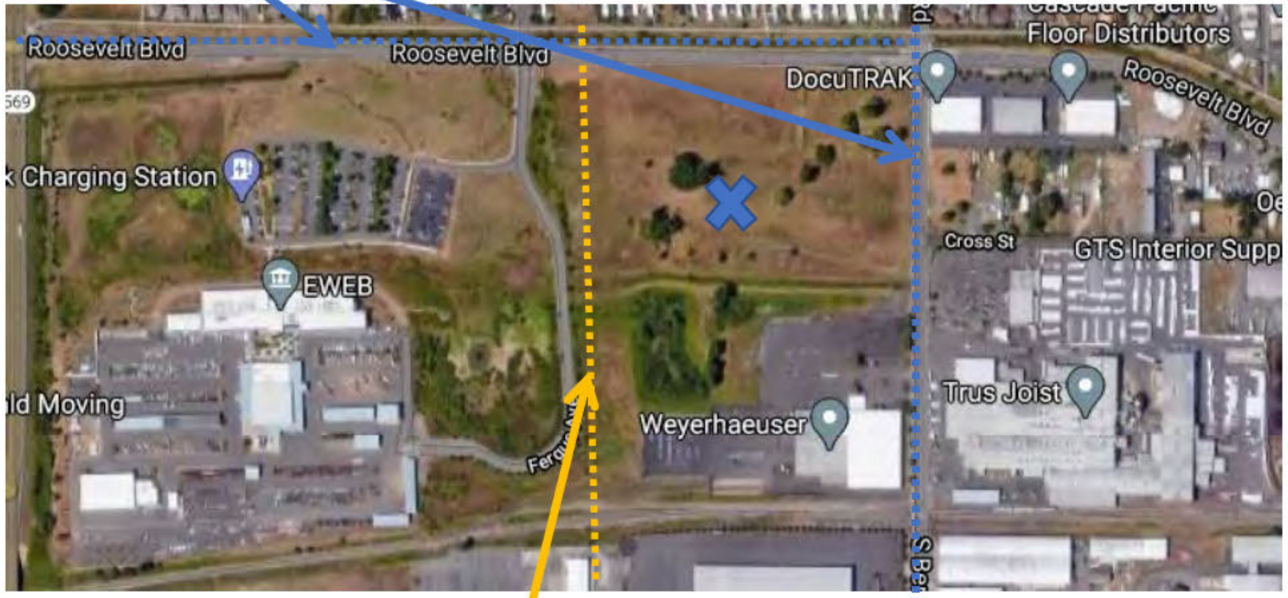
Piloting Blending

Partnering with EWEB and BEF on methanation project

- 1-2 MW demonstration plant
- Generating hydrogen from EWEB power, blending up to 5%

Looking at Short Mountain RNG (EPUD/Lane County) PtG addition w/biocatalyst

NW Natural gas line



BPA transmission line

Power To Gas Methanation Project

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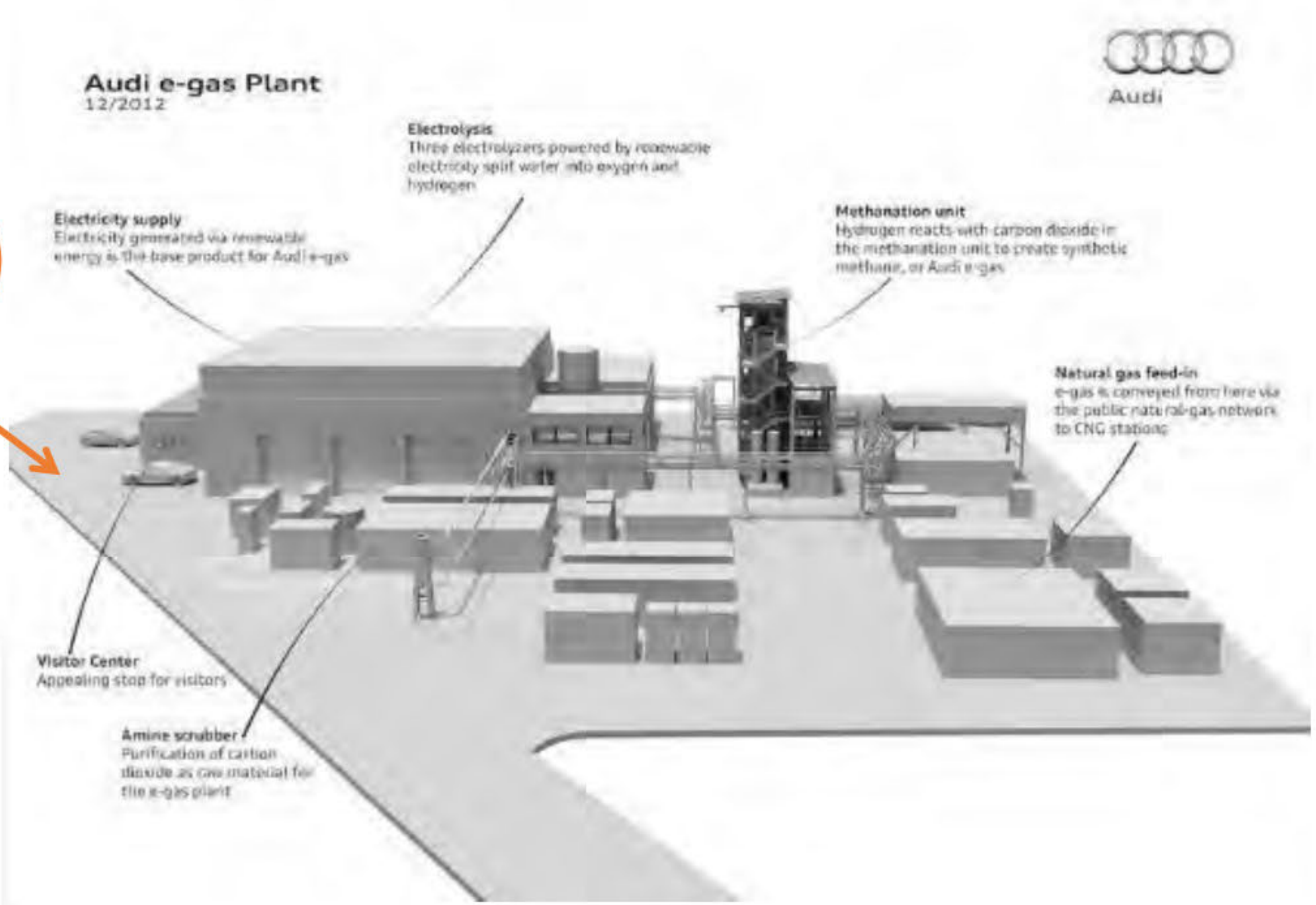
Source: Science Direct



Source: Green Car Congress

- Completed in 2013
- Hydrogen is created on site and combined with CO_2 (MAN chemical methanation)
- Methane is then injected into the natural gas grid

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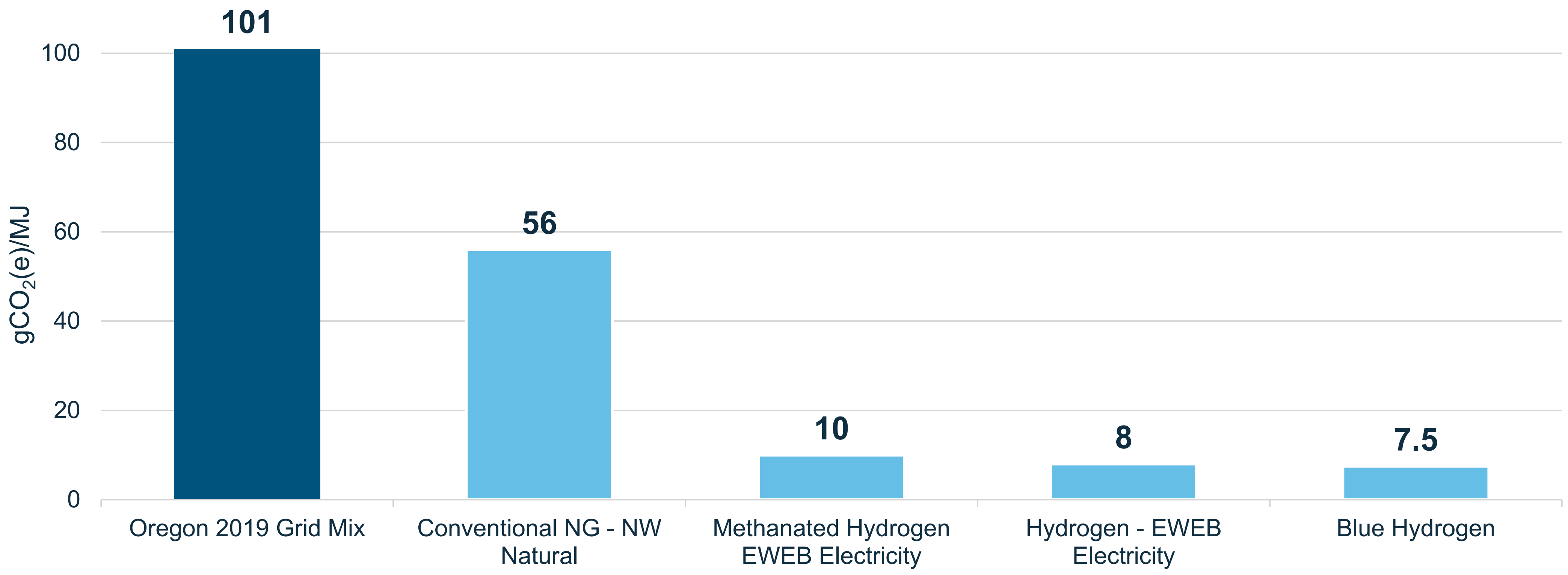
Carbon Intensities of Energy Sources



Estimates using power to gas efficiencies, Oregon DEQ, & California LCFS data

Confidential – Not for distribution outside NW Natural

NW Natural®

Preparing for Hydrogen

Safety is Paramount

- Material compatibility with pipes and components
- Appliance compatibility
- Different flammability characteristics
- Training, standard procedures

System and Customer Compatibility

- LNG
- MIST
- CNG

Energy Delivery

- Likely a maximum of 20% hydrogen (Wobbe)
- Translates to about 8% carbon savings
- Less with RNG
- At 12% falls below gas quality specification

Hydrogen Activities at NW Natural

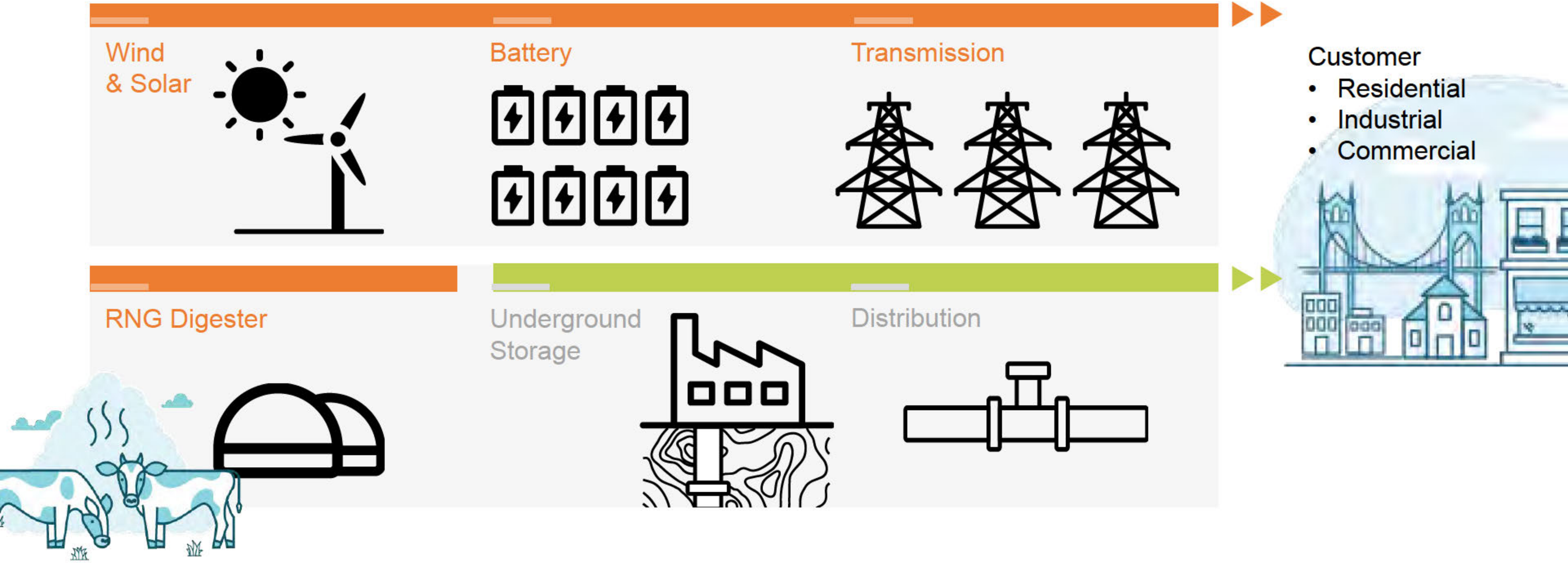
5% Blending at Sherwood

- Test rig
- Training town
- Sherwood buildings
- Customer trials
- System Injection

What is the right cost comparison?

The total cost of reliable low carbon energy services delivered when customers need it.

Additional Investment Required   Existing Infrastructure



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1705

June 6, 2022

CGA Annual Technical Conference 2022

Find Your Energy

Session

Aqeel Zaidi

Annual Technical Conference
Find Your Energy

Natural Gas Heat Pumps

Achieve greater than 100% efficiency with gas heat pumps

June 9, 2022

Aqeel Zaidi, P.Eng

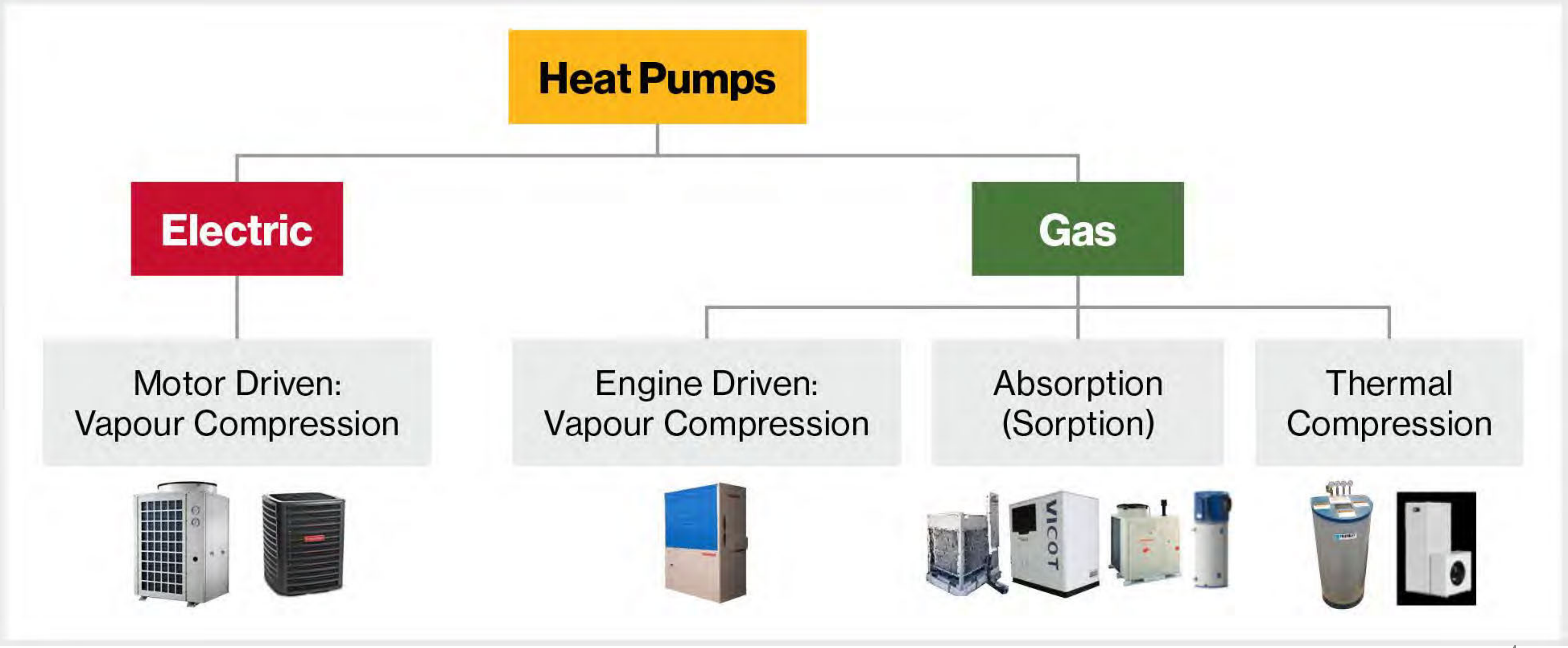
ENBRIDGE

Topics

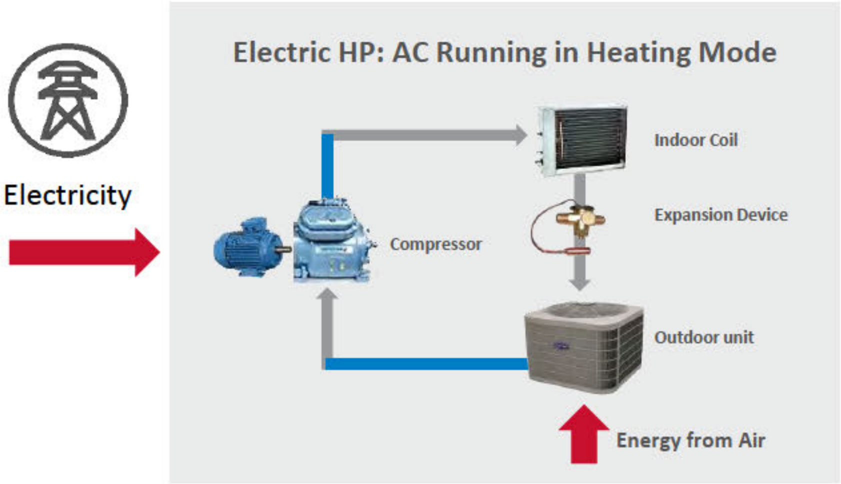
- What is a heat pump and types of heat pumps
- How heat pumps work
- Pathways to achieving residential net-zero with GHPs
- Technology readiness level
- Enbridge Gas' efforts to commercialize GHP technology
- Case studies
- Appendix
  - Resources
  - GHP Product Information

What is a heat pump and types of heat pumps

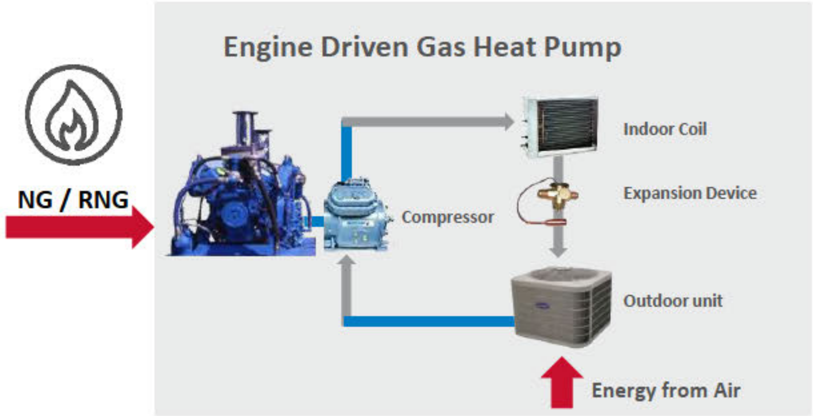
HVAC equipment that moves heat from a cold source (e.g. outdoor air, ground) and delivers it to heat sink (space heating and/or domestic water heating)

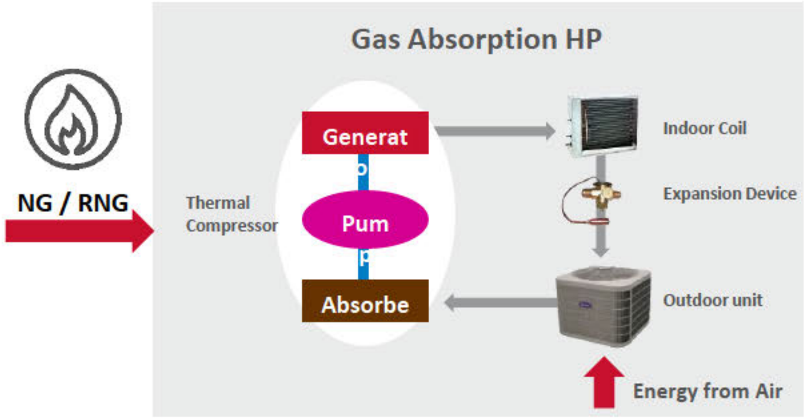


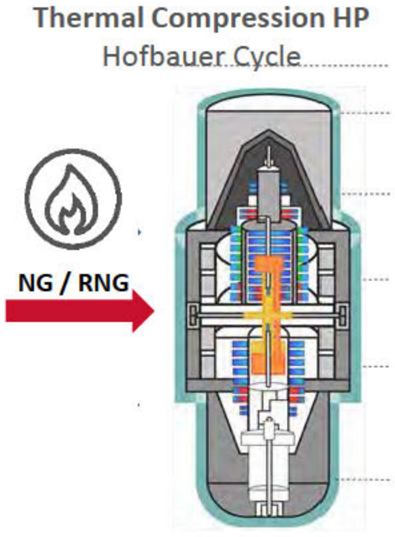
How heat pumps work



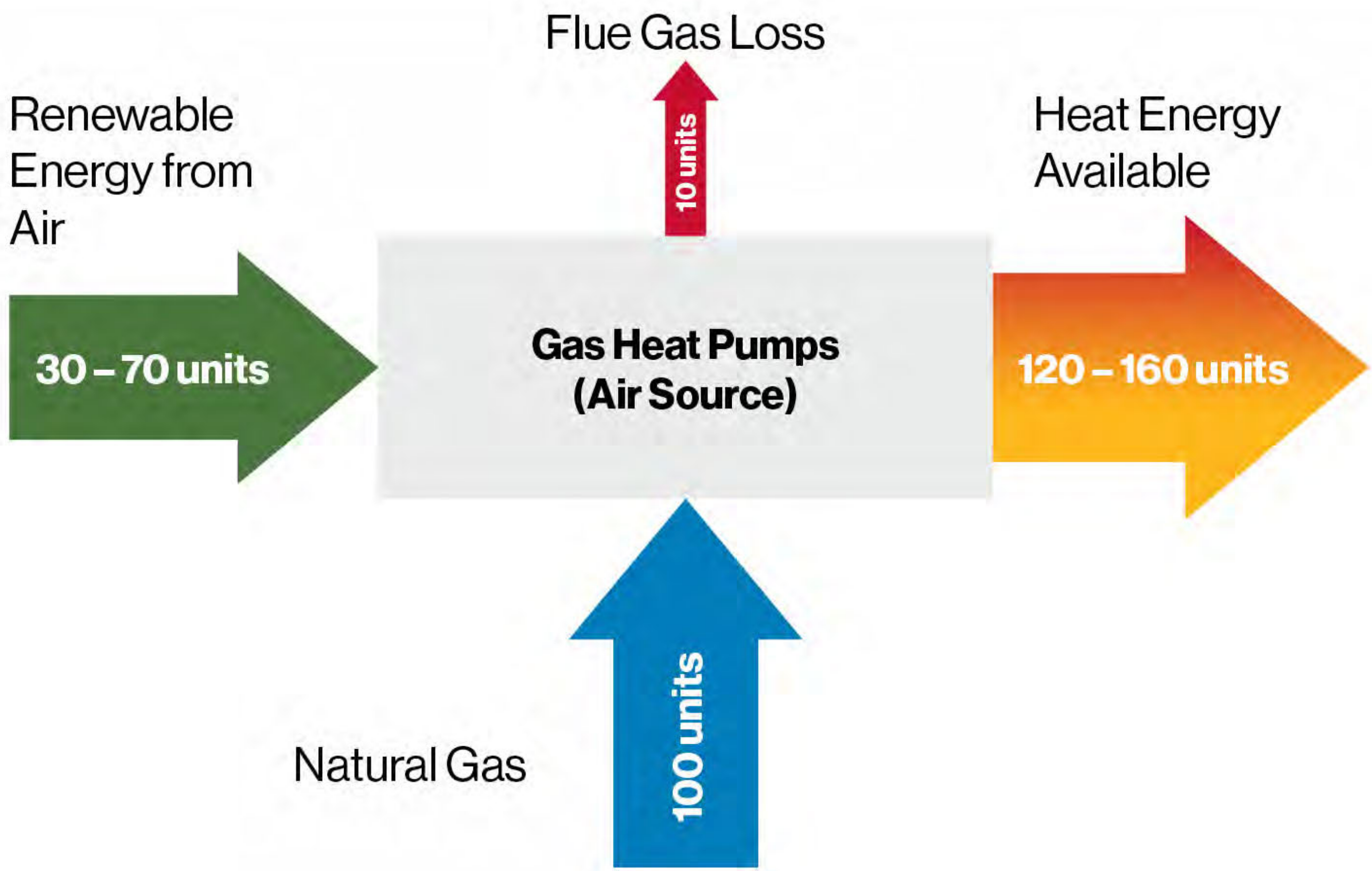
- Electric HP is essentially an air conditioner running in reverse
- In a natural GHP, the electric compressor is replaced with either a natural gas engine driven or thermally driven compression that uses natural gas or could also use Renewable Natural Gas (RNG)







How GHP achieves greater than 100% efficiency



GHPs are an important energy transition pathway

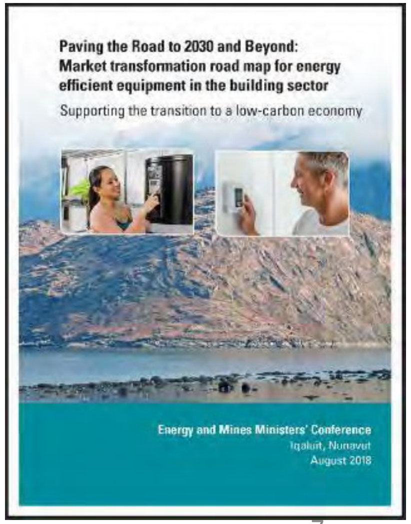
Policy

- The Canadian net-Zero Emission Accountability Act (Bill C-12) will require Canada to achieve net zero by 2050[(1)]

- Federal Govt's Long-term Aspirational Goal requires space & water heating products to exceed 100% efficiency by 2035[(2)]

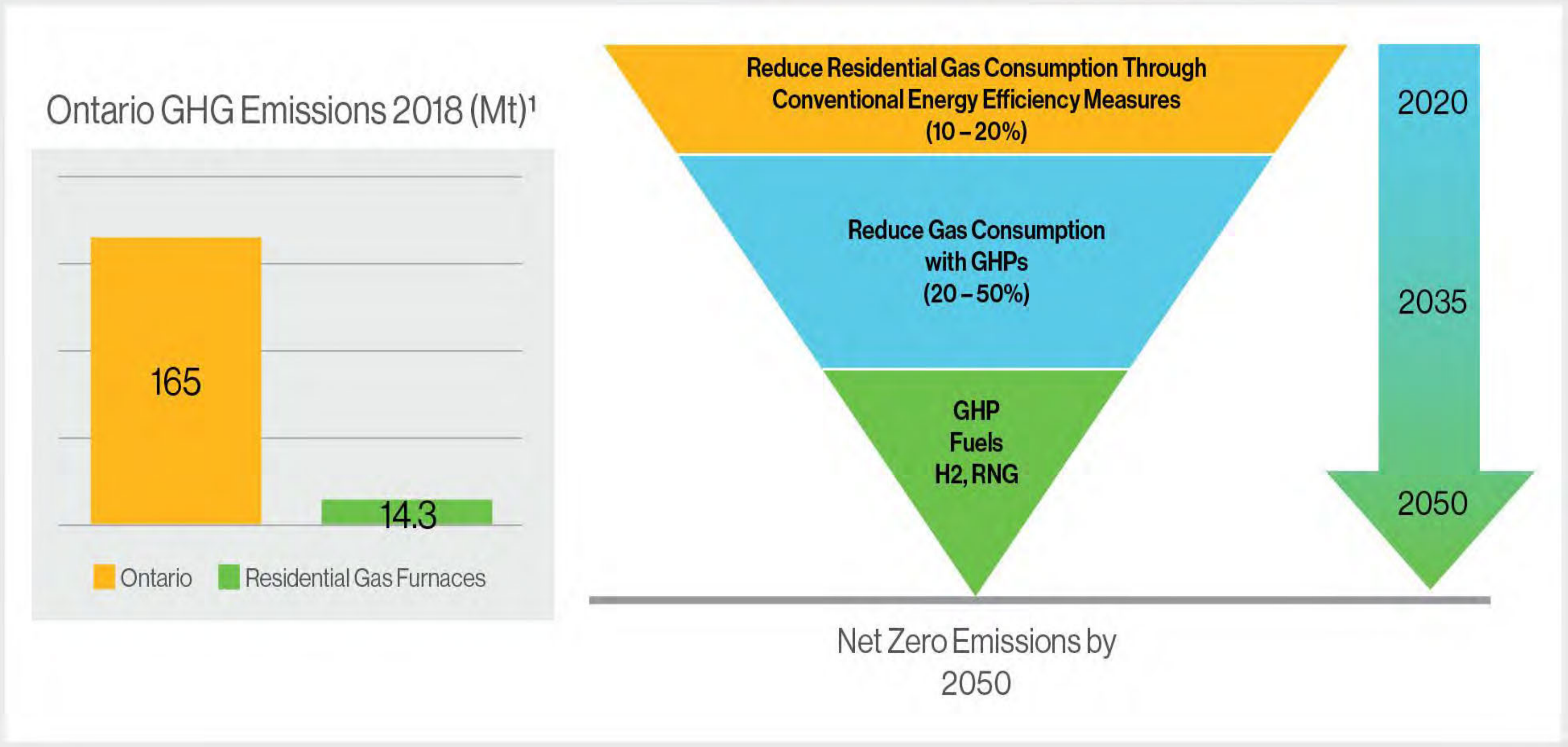
GHP energy transition solution

- GHPs offer cost-effective solution for both space and domestic hot water heating with efficiencies greater than 100%, also potential to include cooling
- Low carbon technologies such as residential Natural Gas Heat Pumps (GHPs) can deliver reductions in carbon emissions and meet future efficiency standards



1. A Healthy Environment and a Healthy Economy, Environment and Climate Change Canada, 2020
2. Paving the Road to 2030 and Beyond: Market transformation road map for energy efficient equipment in building sector, Energy and Mines Ministers' Conference, August 2018

Pathways to achieving residential net-zero with GHPs



1.NRCan,
https://oee.rncan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=9&page=0&wbdisable=true

GHP technology readiness for NA market

Green: Commercially available in Ontario. Grey: Residential products commercially available by 2023/24.

Manufacturer	Type / Avg. Heating COP	Working Fluid	Capacity	Primary Applications	Primary Sectors	Technology Readiness for North America
ROBUR	Absorption 1.2	Ammonia	120,000 Btu/hr, 5T Cooling	Space and DWH heating Cooling (possible)	• Commercial • Residential	• Commercial size unit commercially available • Residential K-18 (62,000 Btu/hr) unit available in Europe. Efforts underway to bring it to NA
YANMAR	Engine driven 1.4	R410	189,000 Btu/hr 14T Cooling	Space heating and cooling	• Commercial	• Commercially available
SMTI ANESI	Absorption 1.2	Ammonia	80,000 Btu/hr	Space and DHW heating	• Residential • Small commercial	• Commercially available (2023) • Field trials of pre-production unit underway
VICOT	Absorption 1.2	Ammonia	68,000 Btu/hr 220,000 Btu/hr 478,000 (GHP +Cond. Boiler)	Space and DHW heating	• Residential • Commercial	• Commercially available in China • Lab testing and field trials of production unit underway in NA
ThermoLift	Thermal compression 1.4	Helium	75,000 Btu/hr 3T Cooling	Space heating, cooling and DHW heating	• Residential • Small commercial	• Commercially available (2023) • Lab testing and field trials of pre-production unit underway
boostHEAT	Thermal compression 1.4	CO2	68,000 Btu/hr	Space and DHW heating	• Residential • Small commercial	• Field trials and lab testing underway in Europe • Commercially available (2024)
Rinnai	Absorption 1.2	Ammonia	10,000 Btu/hr	DHW heating	• Residential	• Lab testing and field trial planned for 2022-23 • Commercially available (2024)

Summary of Enbridge Gas' GHP commercialization efforts

Commercial

8 projects completed
- DHW heating: MURB GTA, *(Robur A)*
- Heating and cooling: Tweed Library *(Robur AR)*
- Heating and cooling: GTA, TRCA *(Robur AR)*
- Heating and cooling (2-pipe system): Office building in Woodstock *(Yanmar)*
- Simultaneous heating and cooling (3-pipe system): Bakery and a convenience store in GTA *(Yanmar)*
- DHW heating: 3 Capreit MURB Properties *(Robur A)*

7 projects underway
- DHW: MURB, GTA, TAF *(V65)*
- DHW for a kitchen in a long-term health care facility: GTA, *(SMTI)*
- Roof Top Units (RTU) for heating and cooling at an aquatic centre, London *(Yanmar)*
- Roof Top Unit (RTU) for heating and cooling at industrial site, GTA *(Yanmar)*
- Space heating and DHW for MURB, TBD *(V140)*
- DHW for a hotel, GTA *(V140)*
- DHW for hospitality sector *(V65)*

Residential

4 SMTI GHP (Space and DHW heating) field trials completed as part of a GTI consortium

- One in GTA and 3 in Chicago area

2 projects underway

- 2 Thermolift (space heating, cooling and DHW) field trials in Ontario

13 projects (finalizing host sites)

- 8 Vicot (space and DHW heating)
- 3 SMTI space and DHW heating)
- 2 ThermoLift (space heating and cooling and DHW heating)

Investment

- Invested $4M CDN in SMTI
- SMTI rolled out ANESI GHP: 80k product

Enbridge Gas DSM offering

- 2022 Incentives available for up to 7 installations for commercial / MURB sector
- Commercially available systems (Robur, Yanmar)

Gas Industry Collaboration

- North American GHP Collaborative (18 major gas utilities)
- ESC GHP Education Consortium
- Gas Technology Institute, Chicago

Technology & Development

- Canmet labs, Ottawa
- Gas Technology Institute, Chicago
- Natural Gas Technology Centre, Montreal

Case Studies

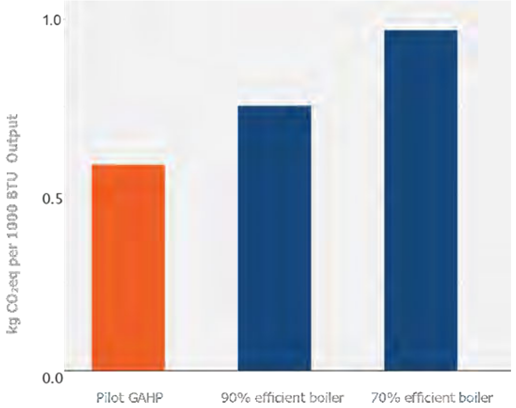
Arleta DHW heating - Robur absorption GHP

Description

- First demo of a GHP for a multi-unit residential building (MURB) DHW heating in Canadian climate
- Building area16,260 m^2, 372 units
- Two 125 MBH Robur GHP to supply base DHW (about 58%) with additional heating provided by condensing boilers
- Location: Toronto

Results

- Mean COP: 1.14
- Annual natural gas saving: 5,390 m^3
- Annual GHG saving: 10.1 tonnes
- Positive results paving the way for GHP DHW heating application in multi-unit residential buildings



Source: The Atmospheric Fund Gas Absorption Heat Pumps: Technology Assessment And Field Test Findings Report 2018

Burnham Farms heating & cooling: Yanmar engine driven 3-pipe GHP

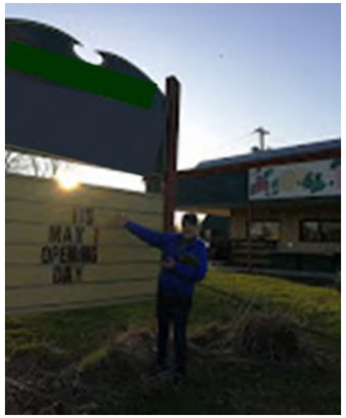
Description

- A family farm market, bakery and convenience store, 7,700 ft^2, Cobourg, Ontario
- One Yanmar VRF 3-pipe system
  - Heating and cooling at the same time
- 14 TR cooling capacity
- 162,000 Btu/hr heating capacity
- Base case heating and cooling: RTU Package System

Results

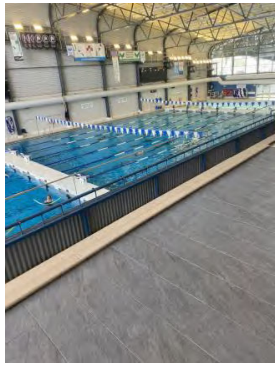
- The system maintains its high-efficiency performance at part load.

	Heating	Cooling
Average COP	1.2	1.5
Cost Savings	30%	60%




Aquatic Centre heating and cooling - Yanmar engine driven GHP RTU



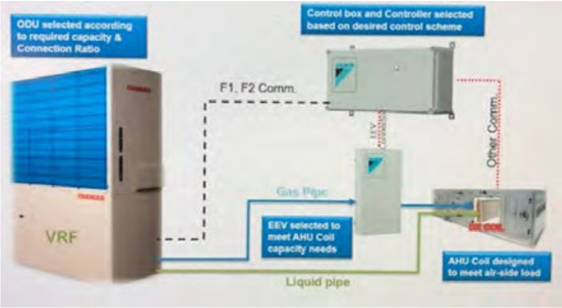


Description

- Aquatic Center training room- City of London
  - 14 TR cooling capacity
  - 168,000 Btu/hr heating capacity
  - Retrofitting One 12 ton RTU
- Custom design matching coil for the existing RTU
- The existing RTU unit is a packaged system with refrigeration coil(s)

Status

- The system has been commissioned in Jan 2022.
- Preliminary results very promising, City of London pleased with the operation
- Final report due Q4, 2022

Integration of RTU with GHP

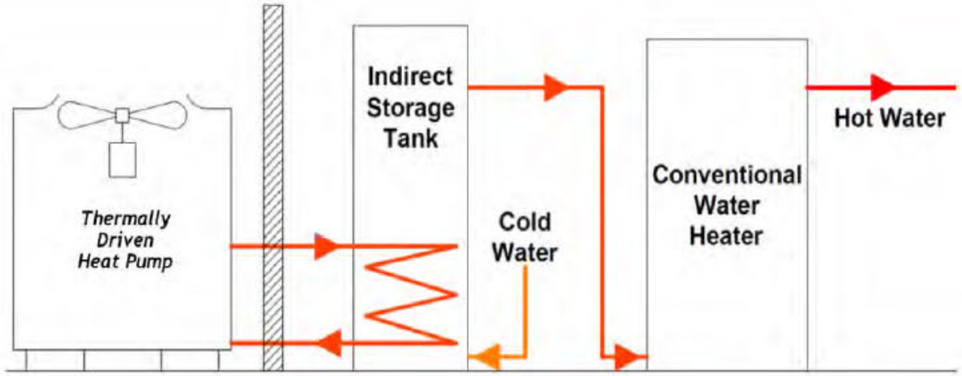
Revera Long Term Care DHW heating - SMTI absorption GHP

Description

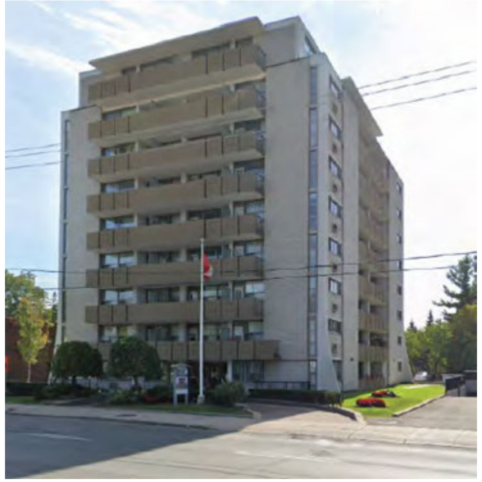
- Output: 80,000 Btu/hr , Input: 55,000 Btu/hr
- COP: 1.4 at 47 F ambient and 100 F return water temperature
- Kitchen DHW heating in a long-term health care facility in GTA
- In series with existing water heating tank
- Pre-heating city water for DHW system
- Other applications: Restaurant DHW heating

Status

- Installation start date: Q4 2021
- M&V underway
- Completion date: Q4 2022



Hollyburn MURB DHW heating - Vicot 65 kW absorption GHP



Description

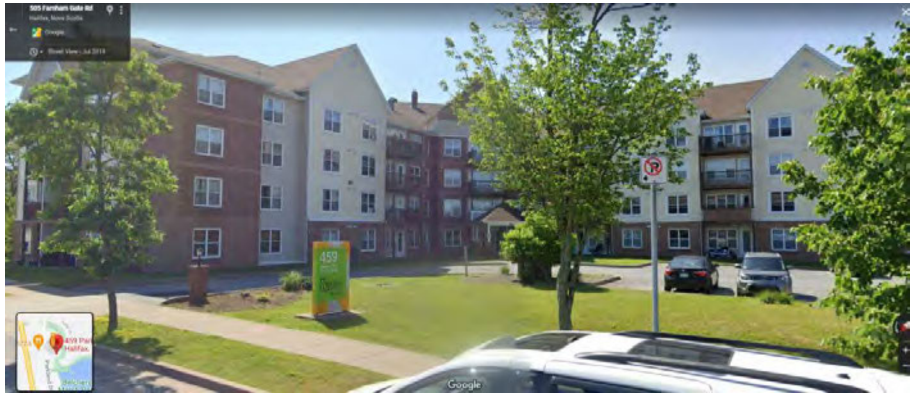
- One unit installed at a MURB in Toronto to supply 100% DHW load
  - 9-storey, 51 apartment units
- First of its kind installation outside of China
- Joint project with TAF
- Nominal heating capacity: 220,000 Btu/hr
- Existing DHW heating system
  - 630,000 Btu/hr boiler
  - 3 x 120-gallon tanks
- Keeping boiler in place for backup

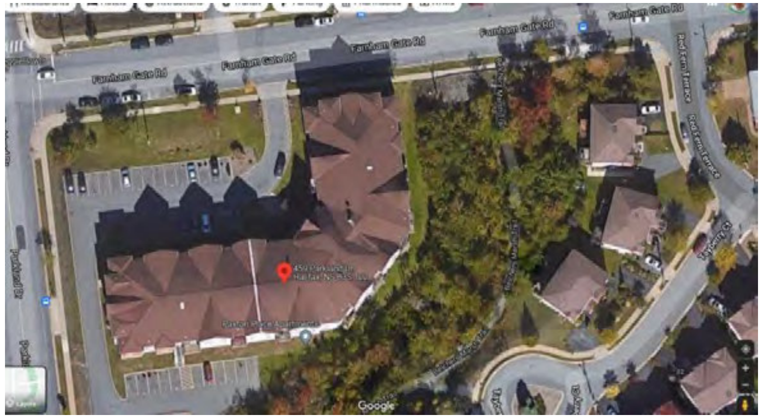
Results

- System is commissioned on Jan 2022
- Preliminary results show about 20% gas saving
- Final report due Q4, 2022

Heritage Gas Halifax MURB Space and DHW heating: Vicot 140 kW absorption GHP

- GHP + Condensing Boiler
- 140 kW (500,000 Btu/hr) Capacity
- 85kW GHP and 55kW Boiler
- Multi Res Building for space heating and DHW heating
- Commissioning underway

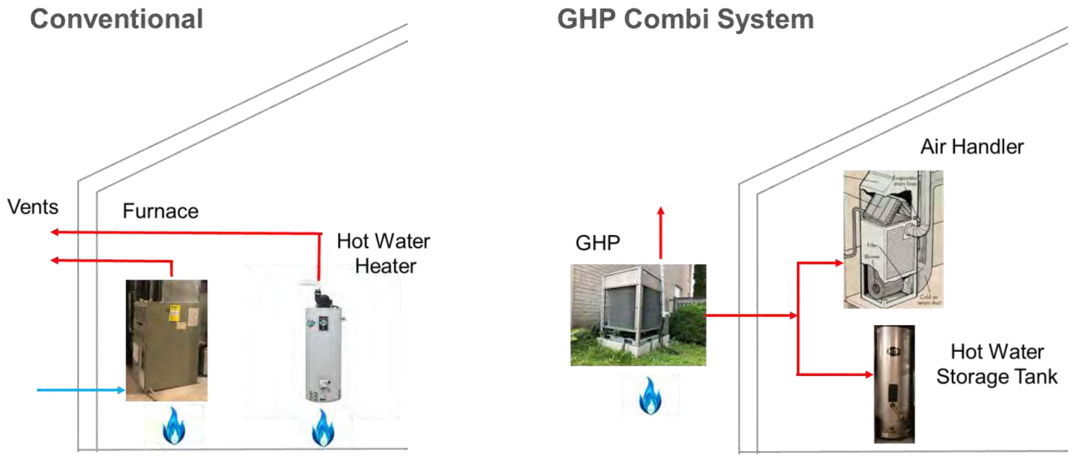




GTI Toronto field trial: SMTI combi residential absorption GHP

Description

- Output: 80,000 Btu/hr, Input: 55,000 Btu/hr
- COP: 1.4 at 47 F ambient and 100 F return water temperature
- One field trial unit installed in Toronto (2020 – 2021) as part of a GTI pilot program



Results

- Significant lessons learned about the installation and operating practices
- Valuable information gathered led to developing pre-production model
- Reliable operation during 2020 – 2021 heating season, providing thermal comfort and DHW to a family of four
- Preliminary COP results
  - COP: 1.1 – 1.45
- Field trial let to developing a plug and play pre-production system

Summary and Conclusions

1. GHPs offer a cost-effective solution for space heating, domestic hot water heating and cooling, with efficiencies greater than 100%.
2. Two GHP products are commercially available now for the commercial sector.
3. Three residential GHP products are on track to be commercially available for the North American market in 2023.
4. GHPs offer a practical pathway to help achieve net-zero emissions by 2050.

Appendix

ENBRIDGE

Resources

1. Enbridge GHP Webinar

- Slide Decks
https://webinars.myescenter.com/2021/Enbridge_GHP_Webinar.pdf

- Video

https://attendee.gotowebinar.com/recording/3697199523722382342

- GHP Brochure

https://www.enbridgegas.com/gas-heat-pump

2. NAGHP Collaborative

https://gasheatpumpcollab.org/

3. Manufacturers' web sites

GHP Product Information

ENBRIDGE®

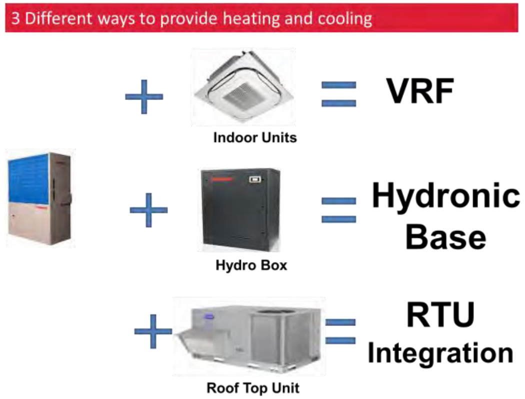
Robur - Absorption Chillers and GHP Commercially available in Ontario for Commercial sector

- Headquartered in Italy, founded in 1956
- 30 years in NA, sales & distribution, Evansville, IN
- Local rep: HTS
- Over 100,000 installations worldwide
- Air source and water source GHPs
  - **Heating only (Ontario focus)**
  - Heating, cooling and supplemental DHW
- Full production and commercialized units readily available for commercial sector
- Refrigerant:
  - Ammonia - environmentally friendly refrigerant
  - Ammonia contained in GHP unit located outdoors

- 120,000 Btu/hr heating, 5T cooling
- COP heating: 1.29
- COP cooling: <1.0
- Minimum ambient operating temp:
  - Minus 20 F (-29 C)
- Stand alone or tandem applications: GHP (base load) + Boiler (peak)
- Ideal Applications: All commercial sector requiring DHW and space heating
- Residential Unit: K18
  - 62,000 Btu/hr space and DHW heating
  - North American unit available late 2021
  - Field testing and certification: 2022
  - Commercially available: 2023

Yanmar – Engine Driven GHP Commercial

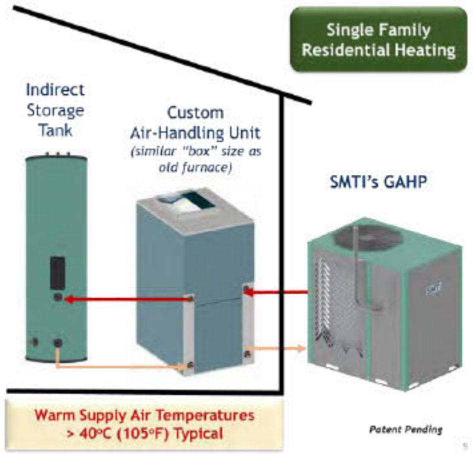
- Head office in Japan, manufactured in USA, with Canadian representative located in Toronto
- Yanmar established in 1912, over 25 years in GHP with 17,000 employee worldwide
- Over 400,000 units have been installed by 2012
- Local rep: Yanmar Canada
- Full production and commercialized units available for commercial sector
- Air source GHPs
  - Heating and Cooling VRF system
- Refrigerant:
  - R410, located outdoors
- 189,000 Btu/hr heating, 14T cooling
- COP heating: 1.4
- COP cooling: 1.3
- Ambient operating temp: 115 F (46 C) to -4 F (-20 C)
- Stand alone or tandem applications
- Ideal Applications: All commercial sector requiring space heating and cooling
- Ancillary units
  - Hdyrobox, to provide hydronic heating and cooling
  - RTU integration

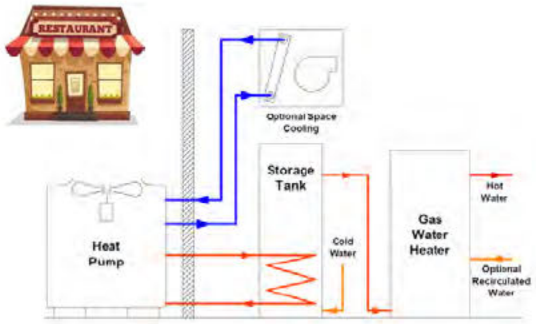


SMTI - Absorption GHP
Residential and small commercial

- Located in Johnson City, TN
- Founded in 2008
- Ontario rep. – under review
- Primary focus:
  - Residential
    - Replace furnace and DHW tank with GHP
    - Plug and plug (outdoor unit, air handler and storage tank)
  - Small Commercial
    - e.g. food service, hospitality, LTC, multi-family
    - DHW applications:
- Refrigerant:
  - Ammonia - environmentally friendly refrigerant
  - Ammonia contained in GHP unit located outdoors

- Product range
  - 10,000 to 140,000 Btu/hr
- Initial focus: 80,000 Btu/hr heating only
- Hybrid product under development
  - GHP combined with electric AC in one box
- COP: 1.43
- Minimum ambient operating temp: -40 C
- Field trials (Canada)
  - GTA (2020- 2021) - completed
  - Emission reduction Alberta - underway
  - Fortis BC - underway
- Certification underway for 80k unit
- Commercialized product launch: late 2022





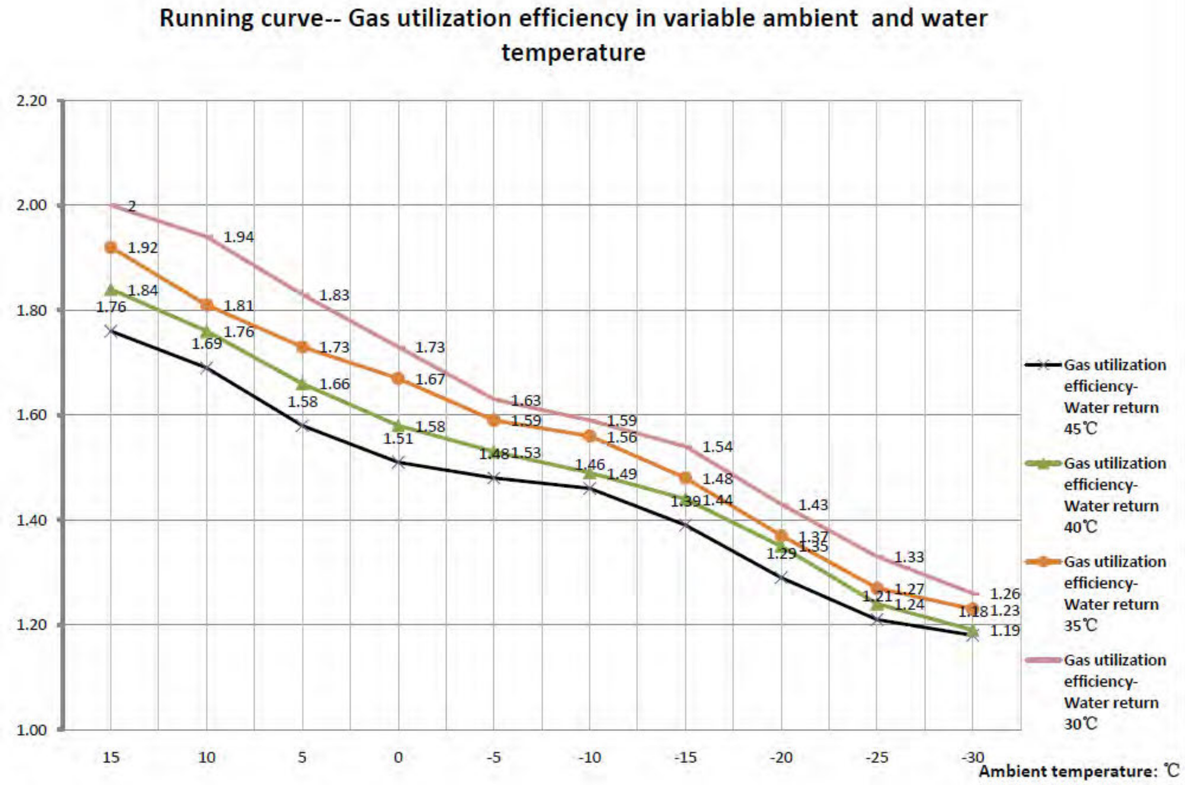
Vicot - Absorption GHP Residential and Commercial

- Manufactured in China, with North America representative located in Toronto
- Established in 2005, 7 production lines and 2000 employee
- Over 20,000 units have been installed in China since 2018 to 2020
- Local rep: Homy Building Solutions
- North American Certification is in process
- Air source GHPs
  - **Heating only (Ontario focus)**
  - Heating, cooling and supplemental DHW
- Refrigerant:
  - Ammonia - environmentally friendly refrigerant
  - Ammonia contained in GHP unit located outdoors

- Range of capacities from 20kW [68 MBH] to 140kW [290 +119 MBH] Combo with Condensing Boiler are available
- COP heating: 1.3 (nominal)
- Ambient operating temp: 109 F (43 C) to -22 F (-30 C)
- Stand alone or tandem applications: GHP + Boiler
- Ideal Applications: All commercial sector requiring DHW and space heating
- Residential Unit – V20
  - 68,000 Btu/hr space and DHW heating
  - NA unit available late 2021
  - Field testing and certification: 2021-22
  - Commercially available: 2023

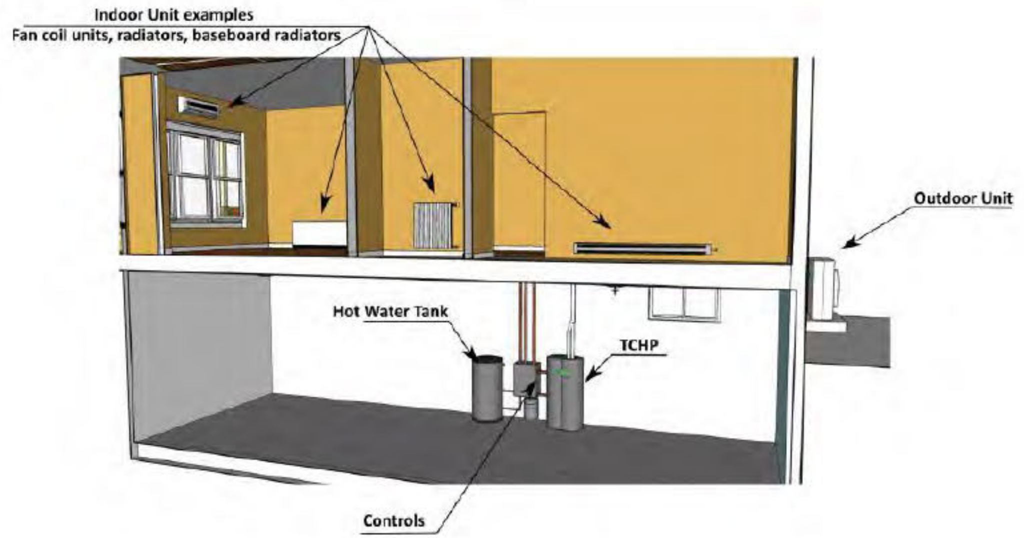
Curve Performance of a residential GHP: Vicot V20

- Residential Vicot 20 kW unit
- GUE varies from 1.85 at 15 C to 1.2 (LHV) at -30 C @ 40C return water temp
- Impact on peak hourly gas consumption at -30 C
  - Absorption GHP technology
  - GUE is about 1.1 on HHV
  - Furnace efficiency is about 92%
  - Reduction in peak hourly gas consumption is about 15%
- Reduces capacity needs of gas distribution network



ThermoLift – Thermal Compressing Residential, small commercial

- Corporate headquarters: Stony Brook, NY
- Founded in 2012
- Manufacturing partner: Linamar, Guelph, ON
- Space heating, cooling and DHW heating from a single appliance
- Heating capacity: up to 75,000 Btu/hr @ 47F ambient temperature
- Cooling capacity: up to 3.1 T @ 47F ambient temperature
- COP: 1.65
- No drop in COP with low ambient temp
- Working fluid: Helium (R-704)
- Demos across Canada starting Q1 2022
  - Ontario
  - Alberta
  - British Columbia



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POLICY
EXHIBIT 1706

REDACTED

Subject to Commission's General Protective Order No. 21-461, this exhibit is Confidential in its entirety and has been redacted.

June 6, 2022

BEFORE THE

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NW Natural

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POLICY
EXHIBIT 1707

June 6, 2022

NW Natural

Summary worksheet for the efficiency comparison between gas heat pump and electric heat pump.
June 2022

ANSI/ASHRAE Standard 105-2021, **Standard Methods of Determining, Expressing, and Comparing Building Energy Performance and Greenhouse Gas Emissions;** Appendix K; Table K-6, Grid Electricity Primary Energy Conversion Factors for Avoided Primary Energy Comparisons; Non baseload Primary Energy Conversion Factor for the Northwest Power Pool (NWPP) or Western Power Pool (WPP).

That Primary Energy Conversion Factor (also known as the Source Energy Factor) is 3.18 for the NWPP. The Source Energy Factor for natural gas is 1.09. So, here is the calculation for comparison purposes:

1. <u>**Avoided or marginal** source energy view:</u>
GHP site efficiency = 160%. Source efficiency = 160/1.09 = 146.8%
EHP site efficiency = 467%. Source efficiency = 467/3.18 = 146.8%

Stated more clearly— using a marginal source energy view, a 160% efficient gas heat pump is equivalent to a 467% efficient electric heat pump

2. <u>**Average** source energy view:</u>
GHP site efficiency = 160% Source efficiency = 160/1.09 = 146.8%
EHP site efficiency = 283.3% Source efficiency = 283.3/1.93 = 146.8%

Stated more clearly— using an average source energy view, a 160% efficient gas heat pump is equivalent to a 283% efficient electric heat pump

Also, from ASHRAE Std 105-2021, Appendix J:

> **J2.8 Avoided Primary Energy and Greenhouse Gas Emissions Comparisons.** Average primary energy and greenhouse gas emissions calculations may be useful for inventory purposes, but they ***may provide misleading information when deciding what energy efficiency*** or conservation measures to include in new building designs or to implement in retrofit programs. . . . . . Using the economic dispatch model, it is unlikely that either renewable or nuclear plants would be affected by the incremental power reduction associated with an energy efficiency or conservation measure. Avoided generation represents the next generation plant used, built, or avoided with that particular fuel type and heat rate and may be location specific***. Avoided generation may be a more suitable basis*** to determine the impact of energy investment decisions on displaced power generation.

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POLICY
EXHIBIT 1708

June 6, 2022

American Gas Association

Review and Comments "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes," Environmental Science & Technology, 2022

Rev 2022.4.14

In January 2022, the journal *Environmental Science & Technology* published "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes" (Lebel et al. 2022). The following Review and Comments present several points, observations, and questions based on an AGA review of the study. A review of the study raises several issues and questions regarding the test methods, measuring instrumentation, emissions sampling of the natural gas cooking appliance types, physical and operating conditions, and other issues. Further investigation and analysis of testing and test results by individuals with the appropriate expertise are needed to sufficiently develop a full and fair exposition of the pertinent facts to enable the public to understand how the authors came to their conclusions or to form independent conclusions.

- The article claims "methane emissions from all gas stoves in U.S. homes have a climate impact comparable to the carbon dioxide emissions of 500,000 cars." The assumptions and calculations for this extrapolation are subject to question. Still, they would translate into only 0.09% of the annual methane emissions in the U.S. (Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks | USEPA).
    - The U.S. Environmental Protection Agency (USEPA) estimates a typical passenger vehicle emits about 4.6 metric tons of carbon dioxide (CO2) per year (Source: Greenhouse Gas Emissions from a Typical Passenger Vehicle | USEPA); for 500,000 cars, that equates to 2.3 million metric tons of CO2 per year; which equates to 26,700 metric tons of methane per year using USEPA's Greenhouse Gas Equivalencies Calculator, which is 0.09% of annual methane emissions.

- The study states, "In addition to methane emissions, co-emitted health-damaging air pollutants such as nitrous oxides (NOx) are released into home air and can trigger respiratory diseases." However, the study did not measure representative nitrogen oxides (NOx) levels in room air. The rate of NOx emissions was measured rather than a direct measurement of NOx in the breathing zone under conditions representative of a typical kitchen.

- The article "found that ovens could produce enough NO_2 to exceed the 1-h ambient standard (100 ppb) within a few minutes." This claim improperly compares instantaneous peak concentrations during the first few minutes of stove usage to a threshold based on 1-hour time-averaged data and has no scientific basis. The shortest measurement time interval that should be used to evaluate against the outdoor air guideline is 1 hour.

- To make strong inferences about the nation, or even just California, requires a larger sample size of no less than 385 homes, preferably not all in the same region. This assumes a 95% confidence level, 5% margin of error, and at least 1.3 million gas stoves in use. Loosening the confidence level to 90% and a 10% margin of error would require 68 sites. (Both cases assume a 0.5 standard deviation.)

- The study did not include emissions from the cooking process, which is just as important, if not more so, than emissions from the burner or heat source operation. Indoor air quality studies have consistently found that emissions from the cooking process can be significant for various classes of pollutants such as particulate matter and volatile organic compounds.

- The Federal Interagency Committee on Indoor Air Quality (CIAQ), which is comprised of two dozen federal agencies led by the U.S. Environmental Protection Agency (EPA), routinely addresses indoor air quality issues of public importance. The CIAQ has not identified natural gas cooking emissions as an important issue concerning asthma or respiratory illness. Furthermore, the U.S. Consumer Product Safety Commission and EPA do not present gas ranges as a significant contributor to adverse air quality or health hazards in their technical or public information literature, guidance, or requirements.

- Federal agencies such as the Consumer Product Safety Commission (CPSC) and the Environmental Protection Agency (EPA) closely monitor and have evaluated homes with natural gas piping and natural gas appliances and have never taken action to limit their use on methane emissions as suggested in this study.

- The appliance manufacturers recommend the installation and use of gas piping and gas appliances in accordance with national consensus standards.

- Natural gas appliances are required to be design certified for safety to appropriate National American National Standards in order to be installed.

- The study does not isolate the methane leakage to the appliance, and the article could not confirm where the leaks originated.
    - The appliance was not isolated from the gas supply equipment as part of this investigation. Specific sources for the leaks were not identified.

  - The tests were performed on gas-leaking appliances or where gas leaks existed in the home gas piping or at the connection of these two, making it impossible to determine which component contributed.
  - There is no indication in the article that the appliances underwent periodic maintenance as specified by the appliance manufacturer.

- The study mentions ignitor issues, indicating the appliances were in disrepair.
  - Consequently, when a correctly functioning gas appliance is properly installed, there should not be any gas leaks.
  - Further, with a properly functioning gas appliance, there is no methane released into the atmosphere when the burner is operating. The combustion chemical reaction does not allow it, meaning that all of the gas being supplied to the burner, including the raw gas being released during the four seconds safety standards allowance during ignition, will burn during the combustion process, and nothing will be liberated as raw gas to the environment.

- There is no indication in the article that the building's gas distribution system, including connections in the piping and connections to the appliances, was verified as properly functioning and sealed before testing.

- The reported leak rates are skewed by a few possible outliers. Even so, the reported average leak rate when stoves are off is only 0.00005 cubic feet per minute.

- There are some potential methodological issues with the study. The measured methane and NOx results were adjusted for dilution caused by leak rates from the test enclosure reported to be 1 to 3 air changes per hour (ACH). That is about five to ten times more dilution than expected for a sealed-off test area.

- The authors may have been testing emissions from commercial appliances, which by code require that vent hoods be installed.
  - The authors noted that the stoves' ages ranged between 3 and 30 years of age, with heat output for each burner ranging from 4500 to 25,000 Btu/h.
  - Commercial burners have higher heat output ranges (25,000 Btu/h), and the fuel gas codes (IFGC & NFGC) require that vent hoods be installed. Using both residential and commercial appliances in this study is inappropriate.
  - Commercial burners are designed, tested, and certified with a specified air exchange rate.

- No uncertainty analysis was conducted, and no independent tests of the method were presented.

Further observations and discussion points

- The scope of the study focused on gas stoves, cooktops, and ovens and includes measurements of these appliances in 53 California homes during all phases of appliance operations.
    - The study sampled a range of appliance brands (18) and ages (3 to 30 years), including appliances with pilot lights or electronic ignition.
    - No appliances in multi-family buildings were sampled.
    - The approach involved partitioning the kitchen with plastic sheets from the rest of the house.
    - This effectively formed a source enclosure where methane and NOx concentrations were sampled from within while the stove was in various states of operation.

- In the U.S., an organic foul-smelling non-toxic gas called mercaptan is added to natural gas to odorize it so that people can effectively detect any natural gas presence.
    - Humans can detect mercaptan at 1.6 ppb (0.0016 ppm) concentrations; therefore, in a typical home, gas leaks in appliances and their connecting gas lines/piping will be very easily detected by the home occupants. The reported concentrations in the study are well below levels that would likely be detected by smell. Nevertheless, it is unclear if the five ranges studied, or any range for that matter had detectable leaks that had not been remedied.

- All certified gas ranges are tested for leaks [with the Manufacturing and Productions Tests required by Section 6 of the ANSI Z21.1 · CSA 1.1 Standard, where subsections 6.1 b) and c)], and common multiple leak points are evaluated during factory manufacture.

- Fuel-fired appliances are designed and installed with the knowledge that there is air movement. The test area was sealed, preventing any normal air movement.

- The article does not indicate if the cavity ring-down spectrometer readings were corrected or adjusted for the presence of volatile organic compounds (VOCs) (due to the presence of common and everyday household items), hydrogen sulfide (present in trace amounts in gas), or other interferents

- Tested gas cooking appliances were not indicated as checked for proper operating rates.
    - The article indicates that nitrogen dioxide (NO_2) was measured directly. However, the instrumentation cited is typically used to measure NOx and nitric oxide (NO), with NO2 calculated by difference rather than directly measured.
    - The article does not state if the NOx results were corrected or adjusted for the presence of nitrous acid or other interferents. Correspondence with the authors indicates that they did not correct for the presence of HNO_2.

Statistical observations

Summary of mean CH4 emission rates of residential stoves, cooktops and ovens.

Source	Number	Mean Emission Rate mg/hr	Lower Confidence Limit (5%)	Upper Confidence Limit (95%)	Comment
steady state stove off	53	57.9	36.3	84	9% of stoves = 49% of emissions
single cooktop burner on	180	259	151	408	9% of burners = 51% of emissions
burner on/off	180	45.9	33.1	64.8	
burner on/off w pilot light	8	258	166	382	estimated ranges
burner on/off electronic	180	38	24	56	estimated ranges
oven pre heat	40	663	408	1030	
oven at temperature	40	759	435	1310	
broiler steady on	31	112	50	186	less on /off cycling

- As shown in the Table, the measured emission rates were characterized by highly skewed, fat-tailed distributions with relatively large confidence limits. Oven operations had the highest emission rates, while single burner emission pulses for pilot light burners were much higher than electronic ignition units. The data for steady-state-off measurements were long-tail skewed, with the top five stoves (9% of sampled units) emitting half (49%) of all steady-state-off emissions. Steady-state-on emission measurements were also long-tailed skewed. The top 5 stoves (9%) emitted 51% of all steady-state-on emissions.
    - The article does not indicate which stoves skewed the results.
    - Did the five appliances in the steady-state off measurements producing 49% of the emissions have standing pilots?
    - Were any of these appliances commercial-grade appliances and not residential?

- The extrapolation of the mean (58 mg/hr) test results to calculate an emission level for the entire country is problematic with the known skewness of the dataset. The median (24 mg/hr) leakage value from the dataset may have been a more representative value. Using the median result would not penalize the national emissions calculation based on a small number of ranges with potential special causes that were not fully investigated.

- It is noted in the report that bootstrapping was performed on the original data set.
    - There are several forms of bootstrapping. Which type was conducted is not indicated, nor were the number of replicate data sets generated in the bootstrapping process.

Regarding Figures

- 5S:
    - The data set appears to be exponential with severe right-sided skewness, yet the graph indicates mean & confidence intervals based on a normal data set.

- In this, the average will be higher than the median in such a skewed data set. What is the median of this data set?

- S8, S9, S10:
  - The data set appears to be non-normal, yet the data presented assumes a normal distribution using the mean (average) and corresponding confidence intervals.
  - What distribution are the data sets and resulting medians?

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1709

June 6, 2022

Issues that Render the Sierra Club/UCLA Study of *Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California* Not Useful for Decision-Making Purposes

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Catalyst
ENVIRONMENTAL SOLUTIONS

CALIFORNIA
RESTAURANT
ASSOCIATION

Introduction

The report *Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California* (UCLA Report), published in April 2020, was prepared on behalf of the Sierra Club by the UCLA Fielding School of Public Health. Several cities in California have passed electrification policies for new construction, and such programs are being considered Statewide. Most of the focus on electrification efforts has been on reducing greenhouse gas emissions in general. The UCLA Report takes a different perspective and focuses on potential health effects rather than greenhouse gas emissions. The UCLA Report advocates that replacing natural gas-fired stoves and ovens with electric appliances would have public health benefits and continued use of natural gas-fired appliances will result in adverse health effects. The discussion of these effects is divided into two main sections: (1) indoor air quality and health effects and (2) outdoor air quality and health effects.

As discussed in this Technical Memorandum, there are several significant flaws in the UCLA Report that undermine its use in decision-making on the topic of the health effects of natural gas stoves and ovens. We identify five major issues and three other issues for this conclusion. The major issues are as follows:

Issue 1: Indoor air modeling results presented in Table 2-2 of the UCLA Report are incorrectly compared to NAAQS and CAAQS. Had the UCLA Report made the correct comparisons, it would have concluded that there are no adverse health impacts from indoor use of natural gas appliances.

Issue 2: The UCLA Report cites several references that conclude that indoor air quality is more a function of what is being cooked, rather than the fuel used for cooking. Emissions from cooking oils and foods would remain in indoor air whether or not there is a transition from natural gas to electric cooking appliances.

Issue 3: The UCLA Report does not consider unanticipated consequences of replacing natural gas with electric stoves and ovens. The focus is solely on combustion of natural gas. Considering the UCLA Report advocates for eliminating natural gas for stoves and ovens, the consequences of electrification (cost and disproportionate adverse impacts to disadvantaged communities, availability, hazards) are certainly relevant and belong in the decision-making process.

Issue 4: The results of the UCLA Report depend upon a sequential series of assumptions, some of which are unsupported by the literature. The approach of the paper leads to compounding (increasing) these uncertainties rather than reducing them.

Issue 5: Numerous statements throughout the UCLA Report are not supported by the data provided or the references cited. Because the UCLA Report is built on data in the published literature, this problem indicates a flawed foundation for the findings.

The technical basis for each major issue, as well as the three other issues, are described in the next sections.

Major Issues

Issue 1: Indoor air modeling results presented in Table 2-2 of the UCLA Report are incorrectly compared to NAAQS and CAAQS. Had the UCLA Report made the correct comparisons, it would have concluded that there are no health impacts from indoor use of natural gas appliances.

Table 2-2 in the UCLA Report presents the key results for the indoor air modeling exercise. The results are divided into two categories for indoor air appliance emissions: (1) stoves and ovens and (2) stoves only. In both cases, indoor air modeling was conducted assuming no venting of appliance emissions to the outside. Within each of these two categories, indoor air concentrations of CO, NO_2, and NO_x are presented under four cooking time scenarios: (1) peak (maximum) concentration, (2) 15-minute cooking time, (3) 1-hour cooking time, and (4) 2-hour cooking time. The following discussion focuses on the three purported exceedances of NAAQS and/or CAAQS as presented in Table 2-2.

Note that of the chemicals presented in Table 2-2, NAAQS and CAAQS are only available for CO and NO_2. NAAQS and CAAQS have not been developed for NO_x. For CO, specific NAAQS and CAAQS are only available for 1-hour and 8-hour averaging times. For NO_2, specific NAAQS and CAAQS are only available for 1-hour and annual arithmetic mean averaging times. Table 2-2 of the UCLA Report did not present modeling results for either 8-hour or annual arithmetic mean averaging times. Therefore, the only relevant comparisons that can be made using UCLA modeling results are CO and NO_2 1-hour average concentrations as compared to their respective 1-hour time-averaged NAAQS and CAAQS; these comparisons are presented in the table below.

Table 1. Comparison of UCLA 1-hour Average Modeled Air Concentrations to Relevant CAAQS and NAAQS

Carbon Monoxide	1-hour Average
CAAQS	20,000
NAAQS	35,000
Stoves and ovens¥	2,300¥
Stoves only¥	900¥

Nitrogen Dioxide	1-hour Average
CAAQS	180
NAAQS	100
Stoves and ovens¥	19¥
Stoves only¥	11¥

All concentrations in ppb.

¥ Modeled 1-hour average concentration as reported in Table 2-2 of the UCLA Report.

As shown in the above Table 1, for both CO and NO_2, the modeled indoor air concentrations for Stoves and ovens and for Stoves only are nearly 10-fold below their respective CAAQS and NAAQS, demonstrating a large margin of safety and absence of potential adverse health effects, even under the unrealistic assumption of no venting of stove and oven exhaust.

In contrast to the appropriate comparison presented in Table 1 (above), the UCLA Report presented several comparisons that are not appropriate nor realistic. For comparison to NAAQs and CAAQs, the UCLA Report compared peak (maximum) concentrations directly to 1-hour NAAQs and CAAQs. **The comparison of maximum peak concentrations to a 1-hour standard is not correct and certainly not relevant for assessing health risks.** The 1-hour NAAQS and CAAQS represent health effects thresholds associated with 1-hour time averaged exposures. It is meaningless to compare a maximum to an average. When the incorrect method of the UCLA

Report is applied, the maximum peak NO_2 concentrations for stoves and ovens (860 ppb) and stoves only (400 ppb) exceeded the 1-hour NO_2 NAAQS of 100 ppb and the 1-hour NO_2 CAAQS of 180 ppb. In contrast, when the average concentrations under the 1-hour and 2-hour cooking scenarios are compared to the 1-hour NAAQS and CAAQS, there are no exceedances. Therefore, the argument that natural gas appliances cause adverse health impacts because they exceed air quality limits is not supported by the data presented in the study.

The UCLA Report has a similarly incorrect comparison for assessing potential chronic exposures. The UCLA Report states on page 20, "[w]e compare the modeled 8-hour time-averaged CO concentrations to the 8-hour CO thresholds, and the 24- hour time-averaged NO_2 concentrations to the chronic NO_2 thresholds, under three cooking-time scenarios (15 minutes of cooking, 1 hour of cooking, and 2 hours of cooking." However, the only chronic exposure exceedance shown in Table 2-2 for NO_2 under the stoves and ovens scenario is apparently based on comparison of 1-year annual NAAQs (53 ppb) and CAAQS (30 ppb) to a calculated 24-hour time-averaged concentration (34 ppb). **A 24-hour time-weighted average concentration cannot properly be compared to 1-year annual standards.** While the calculated 24-hour time-weighted average concentration may be a reasonable estimate of exposure concentration over the course of 24 hours, it is not a reasonable estimate of exposure concentration over the course of an entire year. The unrealistic underlying assumption for this comparison is that cooking, using both stove and oven, without venting, would take place in a residence for 2-hours every single day for 365 days per year. This is contrary to available data on residential occupancy and appliance use and is inconsistent with standard risk assessment practices that recommend assessment of reasonable maximum exposures, often referred to as the RME (DTSC 2015[1]).

Based on data provided by the USEPA[2] for the amount of time spent indoors at a residence by age group, the age group that spends the most amount of time indoors is >65 years. Based on these data, this age group representing the upper-bound exposure spends on average 82% of their time indoors at their residence. Therefore, these maximally exposed individuals would experience no exposure 18% of the time or 66 days each year. Adjusting the 24-hour time-weighted NO_2 concentration of 34 ppb by this factor alone reduces the time-averaged NO_2 concentration to 28 ppb, which would eliminate any exceedances since it is below both NAAQs (53 ppb) and CAAQS (30 ppb). Even this comparison is considered to be highly conservative (and unrealistic) as it assumes that none of the stove and oven appliance emissions are vented to the outside and that these individuals >65 years in age cook every day using both stove and oven at full capacity for 2 hours each day.

Issue 2: The UCLA Report cites several references that conclude that indoor air quality is more a function of what is being cooked, rather than of the fuel used for cooking. Emissions from cooking oils and foods would remain in indoor air whether or not there is a transition from natural gas to electric cooking appliances.

The available data indicates that indoor air quality is more a function of what is being cooked than the fuel used for cooking. The UCLA Report's conclusions gloss over this fact. The UCLA Report does not include this fact in the summarized major issues. Yet the Report is forced to acknowledge this issue repeatedly: it notes that "there are indoor air quality issues associated with the use of gas cooking appliances that will remain despite the implementation of electrification, and we do not account for this. Some PM emissions are associated with cooking oils and foods, and there are no mitigation methods for this, other than the use of ventilation devices such as range hoods. We do not claim that the transition to electric appliances would make a substantial difference in terms of emissions from cooking oils and food.[3]" It also notes that "although many studies have measured $PM_{2.5}$ and UFP [ultrafine particle] emissions from cooking with various types of food

[1] DTSC. 2015. PEA Guidance Manual. October.

[2] USEPA. 2011. Exposure Factors Handbook: 2011 Edition. September. EPA/600/R-090/052F

[3] Page 30 of UCLA Report

and cooking oil, these particulate emissions were often attributed to the food and cooking method rather than the operation of gas appliances.[4]" The UCLA Report also acknowledges that "[o]ne caveat mentioned previously is that cooking can be a significant source of exposure to $PM_{2.5}$ due to heating and combustion of food and cooking oil, resulting in indoor concentrations far in excess of the NAAQS 24-hour threshold.[5]"

The UCLA Report[6] further states, "Gas stoves have been associated with increased levels of indoor CO in California homes, but these increases in concentrations are generally negligible,[27,49,51,52]" and "studies measuring PM2.5 emissions found that increases attributed solely to gas kitchen appliances (with no cooking of food involved, though sometimes a pot of water was heated) were negligible.[49,52]"

While it is clear that what is cooked can have a significant effect on indoor air quality, the UCLA Report buries this beneath the headline statement[7] that natural gas stoves and ovens exceed NAAQS and CAAQS. Moreover, while it is clear that the emissions of some pollutants (in particular CO and PM) from home appliance natural gas usage are negligible, the UCLA Report attempts to implicate these very same pollutants in the context of health effects associated with residential natural gas appliance use. As generally concluded by the references cited in the UCLA Report, PM emissions from gas stoves and ovens are elevated during food cooking but are negligible when burners are on without food cooking, and therefore provide no basis for inferring adverse health effects.

Issue 3: The UCLA Report does not consider unanticipated consequences of replacing natural gas with electric stoves and ovens. The focus is solely on combustion of natural gas. Considering the UCLA Report advocates for eliminating natural gas for stoves and ovens, the consequences of electrification (cost and disproportionate adverse impacts to disadvantaged communities, availability, hazards) are certainly relevant and belong in the decision-making process.

The UCLA Report correctly notes that it does not provide any sort of cost benefit comparison between electric and natural gas stoves and ovens. The UCLA Report notes "[w]e also did not assess any exposures or other dangers associated with electrification, as we focus on combustion pollutants in this report...[t]his report does not compare the benefits and costs of electrification versus improving range hood use and efficiency in terms of reducing indoor air pollution. This is an important consideration that needs to be included in any full-scale assessment of indoor air pollution mitigation techniques.[8]" The UCLA Report notes other studies do provide such cost-benefit analysis, but the citation it provides did not do so.[9]

Another unintended consequence of following the advice of the UCLA Report is that it fails to address the disproportionate economic impact on low-income individuals and families resulting from the higher cost of electrification and elimination of natural gas as an economically efficient energy source. A recent study published in January 2021 by the Berkeley and UCLA Schools of Law[10] has proposed a policy resolution for the

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[4] Pages 9 and 12 of UCLA Report

[5] Page 13 of UCLA Report

[6] Pages 12 and 13 of UCLA Report

[7] A statement that is incorrect, as described in Issue 1 of this Technical Memorandum.

[8] Page 30 of UCLA Report

[9] Page 42 of UCLA Report. The citation, reference 15, is to a National Renewable Energy Lab (NREL) report that does not include the words "stove" or "oven" in it, but is a broader view of electrification. No EPRI reference was evident.

[10] Berkeley Law Center for Law, Energy, and the Environment; UCLA School of Law Emmett Institute on Climate Change and the Environment. 2021. Building Toward Decarbonization. Policy Solutions to Accelerate Building Electrification in High-Priority Communities.

higher cost of electric appliances compared to natural gas appliances: raise the cost of natural gas. While this resolution would make the cost comparable, it seeks to shift the cost burden to low-income individuals and families who rely on natural gas as an affordable energy source by artificially increasing natural gas rates to conform with higher electric rates. The effect of this policy would be to reduce demand for natural gas while financially impacting low-income individuals and families.

Even in the absence of focused policy efforts to increase the cost of natural gas to align with electricity costs, as discussed in the Berkeley/UCLA Schools of Law study, the overall shift away from natural gas usage to full electrification will over time result in gradual increased costs to those dependent on natural gas. As discussed in the National Bureau of Economic Research (NBER) working paper recently published by Davis and Hausman (2021)[11], during the period of this shift from natural gas to electrification, historical capital cost recovery, pipeline and other infrastructure maintenance, and operating costs will remain the same, yet natural gas revenues based on declining consumer usage will decrease. Consequently, the shortfall in revenues will need to be resolved by increasing natural gas usage rates to remaining consumers. Since low-income individuals and families have less financial capabilities to shift from natural gas appliances to electric appliances, it is these disadvantaged subpopulations that will be forced to bear the majority of these increased costs of natural gas.

The UCLA Report also notes that eliminating combustion of natural gas in stoves and ovens will typically lead to increased natural gas combustion at power plants: "One aspect to keep in mind throughout this analysis, which will be mentioned again in the Results and Discussion section, is that electricity generation at gas power plants emits both GHGs and criteria air pollutants. Even if all residential gas appliances were transitioned to electric appliances, the electricity required to power these appliances must still be generated by some form of fuel, and gas power plants currently produce almost half of the electricity generation in the state.[12]"

As illustrated in Figure B-5 of the UCLA Report, the contribution of NO_x from residential gas appliances to outdoor air as compared to the total NO_x emissions from all sources in California is very small. Therefore, the relative net beneficial impact of reduced NO_x to outdoor air from the elimination of residential gas appliances is very likely close to zero given the need to supplement electrical generation with other fuel-dependent power sources. This is also likely the case for the other gas combustion by-products evaluated in the UCLA Report such as CO, PM, and NO_2.

Overall, these unintended consequences of following the advice in the UCLA Report undermines the purported benefits highlighted in the report.

Issue 4: The results of the UCLA Report depend upon a sequential series of assumptions, some of which are unsupported by the literature. The approach of the paper leads to compounding (increasing) these uncertainties rather than reducing them.

The UCLA Report acknowledges that the literature and underlying data are uncertain and inconclusive, and that they collected no new data, and yet their approach was to apply an uncertain model in order to address the uncertainty in the literature data. That is, the underlying data on all these issues is inconclusive, lacking, or in some cases contradictory, yet the Report purports to "analyze" it to draw "clear" conclusions. By relying on the same uncertain data, the model simply compounds this uncertainty with model-related uncertainty:

Page 17: "While there is clear evidence of a relationship between indoor air quality and health, and combustion falls under that domain, there is some inconclusive literature related to gas appliance use and

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[11] Davis, L.W. and C. Hausman. 2021. Who Will Pay for Legacy Utility Costs? NBER Working Paper 28955.

[12] Page 33 of UCLA Report.

specific health effects. The broader relationship between NO_2 and adverse health effects is well-established but a recurrent theme in the literature is the uncertainty regarding the link between indoor NO_2 exposures from gas combustion and respiratory illness. [30,31,113,117]"

Page 29: "Due to the limited scope of this project, we did not conduct any primary data collection; we only analyzed existing literature and datasets. While we used as many relevant data sources as we could access, data paucity was a major limitation for this report. Particularly for conducting future quantitative analyses with regard to equity, the development of additional, publicly available databases to include more detailed and higher spatial resolution data would be a significant asset."

Page 17-18: "While several studies investigating gas appliances and asthma exacerbation produced mixed results, evidence supports a clearer association between gas appliances and asthma and respiratory symptoms in children with one meta-analysis reporting that children living in homes using gas for cooking have a 42% higher risk of having asthma.[33] While we did not estimate the association between specific health symptoms and use of gas appliances, our literature review and analysis aim to clarify the relationship between pollutants associated with gas appliance use and human health…To our knowledge, there are no existing literature review and secondary analysis studies that tie together indoor air quality modeling for various pollutants, housing types, and low-income vulnerability in California."

In conducting studies of the type presented in the UCLA Report, the uncertainties at each step compound, leading to even more uncertain results. While the UCLA Report purports to improve understanding of the effects of indoor combustion of natural gas for cooking, the study design leads to greater uncertainty and less understanding.

Issue 5: The UCLA Report contains numerous statements that are not supported by the data provided or the references cited. Because the UCLA Report is built on data in the published literature, this problem indicates a flawed foundation for the findings.

The UCLA study is a literature-based study; that is, it relies on studies in the published and at times peer-reviewed literature. However, many of the statements made in the report do not correspond to the cited literature. A few examples are provided, which call into question the foundation of this report.

***Example 1*:** In the first paragraph of Section 1.2 it states, "[h]owever, there are significant risks associated with the burning of gas in residences, due to the indoor emission of pollutants, such as CO and formaldehyde (from incomplete combustion), as well as nitrogen oxides (NO_X) such as NO_2 (caused by the oxidation of nitrogen during combustion). Other hazardous compounds emitted from the burning of gas inside homes include volatile organic compounds (VOCs), sulfur oxides, and PM.[20] "

The statement is misleading. The reference cited (Reference 20) is USEPA (1998) *Compilation of Emission Factors*, specifically Section 1.4 (Natural Gas Combustion). This document includes residential furnace and boiler emission factors for CO, formaldehyde, NO_x, NO_2, VOCs, sulfur oxides, and PM. However, there is no mention of potential health risks or the burning of gas in residences in this USEPA document. The UCLA Report provides no basis or specific reference for the statement that "there are significant risks associated with the burning of gas in residences, due to the indoor emission of pollutants…"

Furthermore, use of the term "significant" in scientific reports generally implies statistical significance. The phrase "statistically significant" is used several times in the UCLA Report, but never in the context of the actual evaluations. Not only does USEPA (1998) not refer to statistically significant health risks for any pollutant, as already noted, but in the two instances where the UCLA Report specifically discusses formaldehyde, it acknowledges that there is no statistically significant association between gas appliance use and indoor air formaldehyde concentrations. On pg. 13, the UCLA Report states: "Gas appliances also emit formaldehyde,[27,44,62] but some studies did not find a statistically significant association between gas appliance use and indoor formaldehyde concentrations.[45,46,74]" In this instance, the reference is to the absence of statistical significance. And on pg. 14 of the UCLA Report, it states: "However, an LBNL study of California homes found that although 95% of homes tested had formaldehyde concentrations above the OEHHA chronic REL, these levels were not statistically significantly associated with gas appliances.[45]" and "Due to the lack of emission data and statistically significant evidence reported in the primary literature, we did not include formaldehyde or acetaldehyde in our quantitative analysis." In this instance, the reference is also to the absence of statistical significance. Despite acknowledging the *absence* of any statistically significant formaldehyde emissions associated with gas appliances, the UCLA Report nevertheless asserts "there are significant risks associated with the burning of natural gas in residences, due to the indoor emission of . . . formaldehyde."

Moreover, in Section 2.2.1 Emission Factor Database, and specifically the first subsection entitled *Results of Statistical Analyses*, the only reference to statistical analyses or statistical significance in this entire subsection is as follows: "Consistently, as the year of the publication from which EFs were gathered became more recent, the ng/J emissions decreased (e.g., a paper in 1995 would report higher emissions than a paper published in 2009, with a statistically significant difference); this indicates that emissions have reduced over time. For NO_X, there is a statistically significant increase in EFs for appliances designed to be vented outdoors (e.g., water heaters and home heating devices)." No references were provided for either the 1995 paper for the 2009 paper, and no reference is provided for the statistically significant increase in EFs for water heaters and home heating devices. Moreover, despite the misleading name of the subsection, there is no statistical analyses presented.

Example 2: In Section 1.2 (page 9) it states, "[t]he resulting indoor air pollution can have adverse effects on human health, as Americans spend almost 90% of their time indoors,[21]..." The statement is misleading. The reference cited (Reference 21; Klepeis et al. 2001) does not present any evaluation of potential adverse effects on human health resulting from indoor air pollution. Further, while the survey conducted by Klepeis et al. did report that Americans spend almost 90% (specifically 87%) of their time indoors, **the UCLA Report failed to indicate that only 67% of time is spent inside residences.** Since the focus on the UCLA Report is on residential exposure, 67% of time spent inside residences would be the appropriate metric to present.

Other Issues

Issue	Facts Supporting the Issue	Relevance
The UCLA Report advocates eliminating natural gas stoves and ovens for health reasons. The hypothetical risk, however, is already addressed through existing stove and hood design.	The UCLA Report did not model use of residential appliances under the scenarios of manufacturers' safety recommendations, state regulations, or local ordinances. Can natural gas usage be held accountable for improper use of appliances? Page 18: "Unsurprisingly, the EFs of gas appliances have declined over time, likely due to the technological advances of appliances and pollutant capture technology, which reduce emissions. Consistently, as the year of the publication from which EFs were gathered became more recent, the ng/J emissions decreased (e.g., a paper in 1995 would report higher emissions than a paper published in 2009, with a statistically significant difference); this indicates that emissions have reduced over time. "	The air concentrations of CO, NO_2, and NO_x as reported in Table 2-2 of the UCLA Report are incorrect (over-estimated) because the modeling scenario was not based on use according to manufacturer's requirements (nor on real-world conditions). Therefore, the corresponding health implications discussed in the UCLA Report are greatly exaggerated.
The section on outdoor air quality effects of indoor use of natural gas for stoves and ovens only serves to confuse the issues. For the indoor air emissions exposures, the UCLA Report assumed 0% venting to outdoors; for the outdoor air exposures the UCLA Report assumed 100% venting to outdoors. This is double counting and does not give any consideration to the available science on indoor air ventilation rates and similar relevant subjects. **Furthermore, most of the outdoor air section does not address actual stove and oven emissions, which are a small portion of GHG emissions; instead, it evaluates the effects of reducing fossil fuel emissions on GHG-forming compounds in general, not from stoves and ovens and not related to health effects.**	Page 32-33: "A study modeling the impact of future building electrification found that all-electric homes performed better than mixed-fuel buildings, in terms of both GHG emissions reductions and abatement costs associated with the construction of buildings compliant with the Title 24 California Building Standards.[269]" Page 38: "For the year 2018 (as described in Section 3.2.2), the improvement in outdoor air quality from residential building electrification alone would reduce approximately 354 deaths (all-cause mortality), 304 cases of chronic bronchitis, and 596 cases of acute bronchitis in California (see Table B-5 for confidence intervals for mortality). The most affected counties are the higher Population areas, i.e., Los Angeles County and Orange County, due to the nature of the concentration-response function."	The section on outdoor air quality impacts from indoor use of stoves confuses the issues because it in fact addresses overall GHG impacts and health effects of electrification in general, not solely due to cooking.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1710

Subject to Commission's General Protective Order No. 21-461, part of this exhibit (UG 435 Coalition DR 158 Attachment 1) is Confidential and is being filed in its native, Excel format. No redacted version exists.

June 6, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 Coalition DR 158

158. Please items all costs whether NW Natural seeks reimbursement in this rate proceeding, Docket No. UG 435, for any costs associated with its Community and Government Affairs department, including but not limited to salaries and benefits for employees.

Response:

Please see Confidential UG 435 Coalition DR 158 Attachment 1.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Kimberly A. Heiting and Ryan J. Bracken

POLICY
EXHIBIT 1711

June 6, 2022

NW Natural®

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 Coalition DR 73

73. Please describe whether NW Natural seeks recovery for the costs of industry association dues in this rate case, Docket No. UG 435, and please describe NW Natural's justification for recovery industry association dues in this rate case.

Response:

Yes, the American Gas Association, the Northwest Gas Association, and Western Energy Institute membership dues are included in this rate case for recovery. NW Natural believes that these organizations provide a benefit to NW Natural's customers and are a reasonable business expense that should be recoverable. These organizations keep employees informed and trained, provide opportunities to build and maintain relationships with other entities operating in the natural gas industry and also in many cases directly take on issues that benefit customers (e.g., the AGA engaging in federal tax reform).

The descriptions of these industry associations to further demonstrate the benefit that they each provide are as follows:

AMERICAN GAS ASSOCIATION
The American Gas Association (AGA) represents companies delivering natural gas safely, reliably, and in an environmentally responsible way to help improve the quality of life for their customers every day. AGA's mission is to provide clear value to its membership and serve as the indispensable, leading voice, and facilitator on its behalf in promoting the safe, reliable, and efficient delivery of natural gas to homes and businesses across the nation. The following are some examples of AGA's operations and engineering activities. These activities include initiatives to improve the safety, efficiency and productivity of member companies' engineering and operating functions.

• Technical Committees. AGA's Operations and Engineering section includes technical committees and taskforces: Construction Operations, Customer Field Service & Measurement, Cybersecurity Strategy Task Force, Distribution Integrity Management Program, Engineering, Enterprise Risk Management, Environmental Matters, Field Operations, Gas Control, Natural Gas Security, Pipe Materials, Quality Management, Safety & Occupational Health, Supplemental Gas, Transmission Integrity Management Program, Transmission Measurement, and Underground Storage. These technical committees focus on helping natural gas utilities achieve operational excellence in the safe, reliable, and efficient delivery of natural gas. These committees represent the core functions of gas utilities in the gas delivery supply chain and their work is overseen by the AGA Operations Managing Committee. The Operations Managing Committee is comprised of senior operations executives that review and approve on an annual basis the work of each technical committee.

• Technical Discussion Groups. Since 2012, AGA has provided companies the opportunity to participate in a series of discussion groups intended to help members address operational challenges. These discussion groups serve as virtual roundtables where members hear presentations and exchange information, ideas, and practices.49 The roundtables allow members to network with other utilities that share a particular interest and provide companies the opportunity to include multiple individuals in a discussion group without the burden of extensive travel or time commitments. The 2021 discussion groups are: Asset Management, Corrosion Control, Emergency Management and Public Safety, Emission Reductions, Field Worker Assault Prevention, Hydrogen Blending, Pipeline Safety Management Systems, Renewable Natural Gas, Utilization Pressure Systems, Workforce Development and Training, Work Forecasting and Planning.

• Leading Practices. AGA has played a key part in identifying the industry-leading practices and innovative work techniques that have assisted member utilities in strengthening their safety programs.

• AGA's Mutual Assistance Program and Emergency Planning Resource Center. AGA's Mutual Assistance Program helps facilitate response, recovery, and restoration of services outside the capacity of a company following a natural or other disaster. This program was on call through hurricanes Harvey, Irene and Maria, the fires in California, and other similar events. AGA's program is intended to supplement local, state, and regional assistance programs where the responding company and company in need of aid are not already covered by an alternate agreement. The Emergency Planning Resource Center is a springboard to the AGA Mutual Assistance Program, Situation Reports and Government resources to support all-hazards response, recovery, and restoration. AGA holds an annual National Mock Drill to test response protocols that are required for a large-scale event that would require assistance from other gas utilities.

• Technical Publications. AGA develops and publishes a large number of manuals and technical papers that are essential in the day-to-day operations of gas utilities. Examples of publications of high importance for the safe, reliable and cost-efficient operation of a gas utility system include ANSI B109 standards for diaphragm & rotary meters, ANSI Z223.1/NFPA 54 National Fuel Gas Code, ANSI GPTC Z380.1 Guide for Gas Transmission and Distribution Piping Systems, manuals on Gas Quality Management, Odorization, Gas Measurement, Plastic Pipe, Purging Principles and Practices, Data Governance - Defining Leak Causes for Gas Distribution Systems, Blowdown Emission Reduction, Emerging Technologies to Secure Remote Locations, Leading Practices for Preventing Damages to Meter Sets, Guidelines for Natural Gas

Companies Conducting an Internal Incident and Event Investigation for Safety and Performance Analysis, Supporting and Communicating DIMP within Your Natural Gas Organization, Quality Metrics for Natural Gas Operations, Guidelines for Understanding Key Hole Technology Associated with Corrosion Control, Risk Modeling Approaches for Gas Distribution Pipelines, Effectively Designing Natural Gas Systems, Leading Practices to Reduce the Possibility of an Over-Pressurization Event, and annual industry occupational injury statistics. AGA also produces or works with other organizations to produce consumer safety pamphlets and fact sheets such as bill stuffers and customer communications. AGA is also involved in relevant industry publications/standards. Examples include:

- o NFPA 59A Standard for the Production Storage and Handling of Liquefied Natural Gas
- o ANSI Z21/83 (Gas Appliance Standards)
- o ICC International Fuel Gas Code
- o API 1185 (a pipeline safety public awareness standard under development)
- o API 1164 v3 (Pipeline Cybersecurity Standards)
- Underground Storage Integrity Standards (API 1170/API 1171)

• Operations Conference and Biennial Exhibition. The annual AGA Operations Conference is the natural gas industry's premier gathering of natural gas utility and transmission company operations management for the sharing of technical knowledge, ideas, and practices to promote safe, reliable, and cost-effective delivery of natural gas to the end user. The Operations Conference is AGA's largest forum focusing on such topics as gas measurement, environment, storage, engineering, construction and maintenance gas control, supplemental gas, corrosion control and piping materials. The Operations Conference is AGA's largest event featuring over 100 presentations and roundtables. The conference includes safety achievement awards and presentations by safety award recipients. Every other year, an exhibition is held in conjunction with the Operations Conference that attracts vendors exhibiting tools and technologies to improve safety, operations, and efficiencies.

• Plastic Pipe Manual for Gas Services. AGA's Pipeline Materials Committee evaluates the use of plastic materials and new fabrication techniques for gas piping systems. This Committee publishes the AGA Plastic Pipe Manual for Gas Services, which includes the latest information on plastic materials, piping components, and design as well as installation procedures covered under today's codes and standards for natural gas distribution piping systems. Through the use of this information, member companies can more quickly, confidently, and safely move to increase the use of plastic materials. AGA also assists the Plastic Pipe Institute in maintaining a plastic materials integrity library. This library provides information on historic plastic pipe, fittings and couplings and any known plastic material issues.

• Best Practices Program. The AGA Best Practices Program is an effort to identify effective practices and innovative work procedures that can be used to improve participants' operations and reduce costs. It focuses on improving the safety and efficiency of gas distribution system construction, maintenance, operation, and management. The Best Practices Program features data collection to identify companies that have optimal performance in particular areas. It culminates at roundtables at which companies identified as employing leading practices share their techniques with other program participants. AGA annually features five gas distribution operations topics, such as Emergency Response, New Piping Construction, Damage Prevention, Employee Safety, or Corrosion Prevention. Program participants avoid consultant fees for gathering and analyzing industry data. AGA members have documented millions of dollars in savings from participation in the Best Practices Program. These savings can translate into lower costs for customers.

• SOS Program. The SOS Program is a resource for AGA members who have the need to inquire of other companies on a particular operational or engineering subject. The SOS program is a simple and effective way for members to better understand how others are addressing a particular operational challenge. For example, SOS requests include member-initiated surveys on the following topics:

- o Emergency Preparedness Planning
- o Fire Retardant Clothing Requirements
- o Facility Security
- o Training of Public Safety Officials
- o Leak Investigation Practices
- o Testing Plastic Pipe
- o Safety Requirements for Entering Residences
- o Intermittent Voltage Checks
- o Portable Fire Extinguishers
- o Security for Company Collectors
- o Injury Prevention
- o First Responder Natural Gas Safety Training Outreach During COVID-19
- o PPE Requirements
- o Serious Injury or Fatality Investigations/Evaluations

• Stakeholder Organizations. Furthermore, AGA works with a wide range of government, industry and stakeholder organizations to improve safety and security, including the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration, U.S. Department of Energy, U.S. Department of Homeland Security, National Transportation Safety Board, the National Association of Pipeline Safety Representatives, National Association of Regulatory Utility Commissioners, Common Ground Alliance, and national and regional trade associations.

NORTHWEST GAS ASSOCIATION

The Northwest Gas Association's mission is to advance the safe, dependable, and responsible use of natural gas as a cornerstone of the region's energy, environmental and economic foundation. Its efforts foster greater understanding and informed decision-making among industry participants, opinion leaders, and governing officials in the Pacific Northwest on issues related to natural gas.

WESTERN ENERGY INSTITUTE

Western Energy Institute (WEI) is a trade association serving the electric and natural gas industries throughout the Western United States and Canada. WEI facilitates valuable, direction connections between electric and natural gas industry professional. Through committees, member-driven programs, forums and symposiums, members receive a wide range of access to education, collaboration, and training opportunities.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Reply Testimony of John D. Taylor

LINE EXTENSION POLICY
EXHIBIT 1800

June 6, 2022

EXHIBIT 1800 - REPLY TESTIMONY – LINE EXTENSION POLICY

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium Economics" or "Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400 Hilton Head Island, SC 29926.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Northwest Natural Gas Company ("NW Natural" or "the Company").

Q. Please describe your professional background and education.

A. As a utility pricing and policy expert, I support a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. In the public utility space, I have assisted with asset divestitures, allocated class cost of service studies, rate of return calculations, line extension policies, cash working capital impacts, tax litigation, revenue allocation, rate design, auction analysis, and affiliate cost allocation. I have reviewed and analyzed these subject matters, considering the accounting treatment, the financial investment, and the operational configuration of a company's assets. For utility rate cases, I have performed: allocated class cost of service studies; revenue allocation; rate design; valuation modeling; affiliate cost allocation; and various cost of service analyses. Also, I have filed testimony on class cost of service studies, return on equity, and statistical audit sampling. Specifically, I have presented expert testimony in Florida, Indiana, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, Illinois, Delaware, Pennsylvania, Virginia, Washington, West Virginia, British Columbia, and the Federal Energy Regulatory Commission ("FERC"). Regarding my educational background and professional background, I studied electrical and mechanical engineering and worked for an industrial inspection company, which provided hands-on experience with utility assets and equipment. I received an undergraduate degree in Environmental Economics, with an emphasis in econometrics and regulatory policy. I also earned a Master's degree in Economics from American University in Washington, DC. A copy of my resume is provided as NW Natural/1801, Taylor.

Q. What is the purpose of your Reply Testimony?

A. This Reply Testimony responds to the Direct Testimony submitted by Ed Burgess on Behalf of Intervenors Coalition of Communities of Color, Sierra Club, Verde, Community Energy Project, Climate Solutions, and Oregon Environmental Council (collectively the "Coalition"), and Bob Jenks on behalf of the Oregon Citizens' Utility Board ("CUB") relating to the Company's current tariff Schedule X: Distribution Facilities Extensions for Applicant-Requested Services and Mains ("Schedule X"), also referred to as the Company's line extension policy. NW Natural witnesses Kimberly Heiting and Ryan Bracken address these parties' arguments regarding some of the challenges currently faced by gas distribution companies[1], which underlies their proposals, while my testimony focuses on the appropriate review and application of line extension policies, historically and in the context of a changing utility industry.

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[1] NW Natural/1700, Heiting-Bracken.

Q. Please summarize your principal conclusions.

A. My principal conclusions are:

The sweeping changes recommended by CUB witness Jenks and Coalition witness Burgess are misguided, rely on faulty economics, fail to satisfy fundamental regulatory principles, and rely on several incorrect interpretations/understanding of:

- The role of line extension policy in utility regulation, the method by which NW Natural's line extension allowances ("LEA") are calculated, and the regulatory process ensuring new service extensions are prudent and reasonable;
- The protections provided to existing customers to shield them from subsidizing new customers through line extension allowance provisions;
- The current and future greenhouse gas ("GHG") emission profile of electric generating resources serving Oregon retail customers; and
- The affordability of and logistical requirements needed to fully meet the heating, hot water, and other appliance requirements of the built environment solely with electricity without the continued use of natural gas.

Line extension policy is a common element of natural gas utility tariffs across North America. NW Natural's line extension policy and the construction allowance provided to new customers:

- Provides net benefits to existing customers by reducing the rates they pay relative to what they otherwise would pay had service not been extended to new customers;

- Is based on analyses that protect existing customers, ensuring there is no subsidy to new customers at their expense; and
- Is subject to review by the Public Utility Commission of Oregon ("OPUC") and therefore, subject to the same prudence standard as other utility capital investments.

With the implementation of the Climate Protection Program ("CPP") and Oregon HB 2021 ("HB 2021"), the costs of GHG emission reductions will no longer be an externality of electric and natural gas markets in Oregon. CPP compliance costs are recovered directly from customers and should not be considered in NW Natural's line extension allowance calculation. Doing so results in double counting of the associated cost responsibility, would counter the fundamental regulatory principles of cost responsibility following cost causation, and would represent discriminatory pricing between customers. The investments and expenses related to CPP compliance are driven by the total GHG reduction requirements and the economics of all compliance projects and are not directly related to any single customer being added to the system. Lastly, updating the line extension allowance investment analysis with new inputs results in a higher allowance than the current allowance of $2,875 and as such the current allowance continues to provide economic benefits to existing customers.

Q. How is the remainder of your rebuttal testimony organized?

A. In Section II, in response to witness recommendations for significant changes in NW Natural's line extension policy, I discuss the role and application of line extension policy in utility regulation. In Section III, I discuss NW Natural's line extension policy. In Section IV, I address specific points made by CUB witness Bob Jenks related to NW Natural's line extension policy. In Section V, I address specific points made by Coalition witness Ed Burgess related to NW Natural's line extension policy. In Section VI, I summarize my conclusions and provide my recommendations.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring Exhibits NW Natural/1801 through 1804, as presented in the following table.

Table 1 – Reply NW Natural Exhibits

NW Natural Exhibit NW Natural/1801, Taylor	Resume of John D. Taylor
NW Natural Exhibit NW Natural/1802, Taylor	NW Natural Response to CUB DR 52
NW Natural Exhibit NW Natural/1803, Taylor	NW Natural Response to Coalition DR 33
NW Natural Exhibit NW Natural/1804, Taylor	Updated Investment Analysis for Residential Line Extension Allowance

II. LINE EXTENSION POLICY – ROLES AND APPLICATIONS

Q. What is the goal of a regulatory commission in setting construction allowances and tariff rules and policies relating to the extension of service to new customers?

A. The overarching goal of a line extension policy is to set the rules and utility practices that govern the extension of gas distribution service to new customers. The line extension policy directs a utility's operational processes to ensure consistency in applying the rules across all customers requesting service. Further, the line extension policy and associated construction allowances set the costs of service for new customers and are embodied in tariffs per the requirements of regulatory commission rules, administrative codes, and prior regulatory case precedents. The line extension policy is also in place to ensure equity between existing and new customers, where existing customers are held harmless by not paying for the portion of new service costs that are uneconomic yet benefit from the incremental revenues in excess of the cost related to the new customer's service, which contribute to paying for common costs.

Q. How does the integration of new customers result in benefits to existing customers?

A. From an operational standpoint, integrating new customers into a utility's distribution system leads to internal efficiencies, lowering the average cost of a utility's service to both new and existing customers. This is due to the realization of economies of scale, where the average unit costs of providing service to a customer are lower as additional customers are added. Secondly, additional revenues from new customers offset the recovery of common costs resulting in lower prices for all customers over time. The nature of utility operations is characterized by the existence of joint use facilities. Common costs include facilities that are jointly used by different customer groups, operating and maintenance ("O&M") expenses associated with joint-use facilities, and administrative and general expenses common across customer groups and functions of the utility. This is due to spreading fixed costs across a greater number of customers. Lastly, existing customers can benefit from economies of scope where cost savings are achieved from providing service to two or more distinct groups of customers.

Q. How are line extension allowances set to ensure fairness between new and existing customers?

A. A common approach to setting line extension allowances is to set the allowance based on a calculation that compares the expected revenues from new customers and the direct incremental cost of providing service to new customers. When the direct incremental costs are above the expected revenues over time, the customer is required to contribute directly to the construction costs. Various methods used to conduct this calculation are further described below.

Q. Do OPUC rules reflect the approach mentioned above?

A. Yes. Oregon Administrative Rules ("OAR") - Rule 860-021-0051 states:

> Each gas utility shall develop, with the Commission's approval, a uniform policy governing the amount of main extension which will be made free to connect a new customer. This policy should be related to the investment that can prudently be made for the probable revenue.[2]

Furthermore, OAR 860-021-0050 states:

> (1) Each gas utility shall furnish, a gas service from the gas main adjacent to the customer's premises to and including the meter. Each gas utility shall develop, with the Commission's approval, a uniform policy governing the amount of service extension that will be made free to connect a new customer. This policy should be related to the investment that can prudently be made for the probable revenue.[3]

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[2] OAR 860-021-0051.

[3] OAR 860-021-0050.

Q. What recent reviews of line extension policies were undertaken by the OPUC?

A. In June 2020, Portland General Electric Company ("PGE") filed a request to update their line extension allowances with this Commission. PGE asserted that the proposal to restructure its residential allowances supports Oregon's decarbonization goals, as outlined in the Governor's Executive Order No. 20-04 ("EO 20-04"), by providing an incentive to electrify and therefore decarbonize residential loads. The Order states: "However, Staff's analysis and recommendation does not rely on PGE's assertion, but instead relies only on applicable statutes and rules."[4]

Q. What line extension allowance principles did the Commission cite in its final Order adopting Staff's recommendations with modifications in this proceeding?

A. The final Order states:

> Staff affirms its position that a line extension allowance should hold other customers harmless - that is, in its review, Staff's goal is to ensure that the proposed line extension allowance does not result in higher residential rates. To ensure that, the expected incremental revenues from the new customers are compared to the amount of the line extension allowance. Another consideration is to treat customers equitably. Since all residential customers have likely been eligible for line extensions, there should be a consideration of equity among customers for the line extension allowances they received.[5]

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[4] *In the Matter of Portland General Electric Company, Advice No. 20-14 (ADV 1130), Schedule 300 Line Extension Allowance*, Docket No. UE 385, Order No. 20-483, App. A at 3 (Dec. 23, 2020) (available at: https://apps.puc.state.or.us/orders/2020ords/20-483.pdf).

[5] *Id.* at App. A at 4.

Staff also affirmed that its recommendation was consistent with the past practice of evaluating line extension allowances on an economic basis.

> Finally, in making this recommendation, Staff reaffirms that it has not relied on PGE's assertion that it's proposed residential LEAs will support the goals of EO 20-04. Staff's recommendation is consistent with its past practice in evaluating LEAs on an economic basis.[6]

Q. What is the economic basis cited in this Order?

A. The final Order describes the balancing of the interests of new customers and existing customers, where a line extension allowance should recognize that new customers help pay for common costs, and the larger the customer, the larger the appropriate allowance, while noting that a line extension allowance should not result in higher rates.

> Line extension allowances are a common practice in the utility industry. Most electric utilities have a line extension policy that outlines how costs are allocated and incurred to extend service to new customers. Generally, the utility provides a credit against the cost for providing services up to the customer property location.
>
> The amount of the credit is the amount not collected from the customer. This means that the credit is essentially the amount that is added to the utility's rate base and included in overall revenue requirements. Given that the new customer will contribute revenues to the system which help pay for common costs, PGE is recognizing that a larger use customer should provide greater margins and thus can be offered a greater line extension amount. A limiting factor in the amount of the credit is to ensure that amount of the line extension does not result in higher rates to other customers since the credit is included in revenue requirements.[7]

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[6] *Id*. at App. A at 8.

[7] *Id*. at App. 3-4 (citing RAP Electric Cost Allocation for a New ERA, page 59: https://www.raponline.org/wpcontenUuploads/2020/01 /rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf).

Q. Are line extension policies and associated construction allowances a common element of utility regulation across North America?

A. Yes. All utilities have tariff rules, commission-approved methods, and associated internal policies to guide the utility's operational processes when extending service to new customers. These exist for both electric and natural gas utilities and encompass four primary methods of setting construction allowances:

- Dollar Allowance: The construction allowance is a fixed cap dollar amount. This allowance is then used to offset the costs of extending service to a new customer, where the customer bears the costs in excess of the fixed cap allowance.
- Footage Allowance: The construction allowance is a footage allowance based on the distance from a distribution main. The customer bears the costs for any excess length above the footage allowance.
- Investment Analysis: Investment analyses involve comparing expected revenues from new customers to the utility's incremental costs. Using a net present value ("NPV") test subtracts the discounted costs of the extension from the expected discounted revenues over some period of time. If the difference is positive, the utility would consider the line extension an economical and financially viable investment. If the difference is negative, then the utility would require a customer contribution to reduce the costs to a point where the difference is zero or positive. Some investment

analyses use an internal rate of return ("IRR") methodology. This approach solves for a rate of return that sets the net present value of all cash flows from the investment (both future distribution margin revenues and future incremental costs) equal to zero. Lastly, some utilities use a perpetual net present value method. Under this approach, the maximum level of economic investment equals the net present value of the annual distribution margin in perpetuity. This method was recently reviewed by the Washington Utilities and Transportation Commission ("WUTC") and is further described in the next section of this testimony.

- Revenue Multipliers: The construction allowance equals a multiple of annual expected non-fuel base distribution margin revenues. Under this method, expected revenues are derived from particular project assumptions or average usage characteristics for a class of customers or customers with specific equipment types.

Q. Does a utility typically apply only one of the construction allowance methods?

A. No. Many utilities rely on multiple methods depending on the customer class or project characteristics. For instance, they may apply a footage or dollar allowance for a typical residential dwelling but apply a more detailed investment analysis for larger non-residential projects (as is the case with NW Natural's Schedule X). Further, utilities often use an investment analysis of average customer and construction costs to inform dollar allowances, footage allowances, and revenue multipliers. The utility can then ascertain if the allowance amounts result in economically efficient outcomes. This was the case with NW Natural in their 2012 general rate filing, docket UG 221, where the Company used an investment analysis to support the determination of the dollar allowances proposed in that proceeding.

Q. What are some other attributes of line extension policies utilized by utilities across North America?

A. Line extension policies are widely used by utilities across North America. Each is implemented with the recognition that extending service to new customers benefits existing customers. The policies themselves vary among each utility, but many have similar components. These include a method for determining system extension profitability (i.e., discounted cash flow ("DCF") model, NPV analysis, and Investment Analysis), a basis for determining (and exceptions to) the contribution in aid of construction ("CIAC"), refunds of contributions to customers, the process to estimate costs, and municipal or regulatory compliance requirements.

III. NW NATURAL'S LINE EXTENSION POLICY

Q. Can you please describe the content of the CUB and Coalition testimonies to which you are responding in this Reply Testimony?

A. Both CUB's and the Coalition's Direct Testimony recommend sweeping changes to the Company's current Schedule X tariff, emphasizing reducing or eliminating line extension allowances used to determine the required customer contributions. These line extension allowances are defined in the Company's Schedule X and are considered when NW Natural extends its gas distribution system to new customers.

Q. What is the content of Schedule X?

A. In general, Schedule X defines the processes and provisions related to distribution facilities extensions for applicant-requested services and mains. Schedule X includes information on the general conditions of service, location, construction costs, requirements for new or planned development, the construction allowances and investment analysis for different customer types, required construction contribution from customers, service agreements, and the application of refunds. It consists of eight pages within NW Natural's tariff.

Q. Did NW Natural propose any changes to Schedule X within its initially filed case?

A. No. NW Natural proposed no changes to Schedule X as part of their filed case and, as further described in this testimony, the Company did not suggest changes be implemented as part of this proceeding.

Q. To what portions of Schedule X are CUB and the Coalition recommending changes?

A. CUB and the Coalition are focused only on the line extension allowances provided for in the Construction Allowance section of Schedule X. That section defines the Construction Allowance based on the classification of customers between (1) Residential and (2) Non-Residential and Planned Developments and further defines specific Construction Allowances for Residential dwellings. Table 2 below summarizes the Construction Allowances for Residential Dwellings set in Schedule X.

Table 2 – Schedule X – Construction Allowances for Residential Dwellings

Category	Description	Construction Allowance (per premise)
A	Primary natural gas space heating (does not apply to centralized space heating that serves multiple units)	$2,875
B	Primary natural gas water heat (does not apply to centralized water heating that serves multiple units); natural gas heating fireplace for primary space heating; natural gas wall heat for primary space heating	$2,100
C	Range, cooktop, clothes dryer	$ 850
D	Gas barbecue, log lighter, gas log, tiki torch, Bunsen burner, pool, spa, or hot tub water heaters, standby space heating equipment including but not limited to natural gas backup to electric heat pumps; non-primary space or water heat equipment; equipment installed in a detached garage, shop, or outbuilding	$0

For Non-Residential and Planned Developments, Schedule X states the Company will perform an investment analysis for each installation to determine the amount of any Construction Allowance. At a minimum, the Construction Allowance will equal 5.0 times the annual margin revenue NW Natural estimates it will generate from the new load.

Q. How does NW Natural apply Construction Allowances to new service extensions?

A. For residential extensions, the Company estimates the installation cost and requires the customer to contribute funds equal to the difference between the installation cost estimate and the construction allowance (see Table 2 for the categories of residential construction allowances).

Q. How were NW Natural's Construction Allowances determined and set in Schedule X?

A. The current residential construction allowances included in Schedule X were determined in the Company's 2012 rate case. The actual amount of $2,875 was based on the financial calculation proposed in the Company's filing in docket UG 221 and approved in Order No. 12-408. The model used for that calculation was provided in NW Natural's response to UG 435 CUB DR 52 as an excel file titled "UG 435 CUB DR 52 Attachment 1.xlsx." NW Natural's response to UG 435 CUB DR 52,[8] including Attachment 1, was submitted by Coalition witness Burgess as Exhibit Coalition/213.[9] As NW Natural explained in its response to UG 435 CUB DR 52, the methodology used to determine the allowances was to set the construction cost or allowance such that a revenue stream for different terms (corresponding to the different "Categories" in Schedule X) created an IRR set at the Company's cost of capital.

[8] The response is attached as NW Natural/1802, Taylor.

[9] The ultimate residential allowance of $2,875 is a slightly downward adjustment from the $2,900 calculated by and included in Company's filing in docket UG 221.

Q. How are NW Natural's Construction Allowances determined for non-residential customers?

A. Non-residential allowances are calculated on a case-by-case basis in the software program Experlogix, which was described in NW Natural's response to UG 435 Coalition DR 33.[10] The allowance is determined by performing an investment analysis as described in Schedule X, on Tariff page Sheet X-6 under the section Non-Residential and Planned Developments:

> The Company will perform an investment analysis for each installation to determine the amount of any Construction Allowance. At a minimum, the Construction Allowances will equal 5.0 times the annual margin revenue that is estimated to be generated from the operation of natural gas-fired equipment to be installed at the service address. The Company will estimate therm usage associated with the operation of gas-fired equipment based on structure characteristics, the type and frequency of use of the gas-fired equipment, and the nameplate rating of the gas-fired equipment to be installed.

Q. Were details provided on the methods used to set line extension allowances by NW Natural?

A. Yes. NW Natural offered in response to UG 435 Coalition DR 33 to provide a demonstration of the Excel-based model used to set the current line extension allowances. NW Natural provided a description and screenshots of the Experlogix program, which is embedded in their CRM system and offered to provide a demonstration of this program. The Coalition did not acknowledge the Company's offer to provide a demonstration, and the Company remains open to do so.

[10] *See* NW Natural/1803, Taylor.

Q. Do the methods employed by NW Natural to calculate its line extension allowance ensure new customers are paying their fair share and existing customers benefit from the addition of a new customer?

A. Yes, these assurances are embedded in NW Natural's line extension allowance calculation model, provided in NW Natural's response to "UG 435 CUB DR 52" as "Attachment 1".[11] In calculating the residential line extension allowances in the Company's filing in UG 221 (which were approved in Order No. 12-408), "Attachment 1" shows:

- When a new customer is added to the system, it provides additional distribution margin revenue to cover its non-commodity cost of service ($371 in year 1).[12] The new customer also directly causes an increase in expenses, including O&M, depreciation, franchise tax, property tax, and income, offset by the tax benefit of the investment ($146 in year 1).[13] This results in an increase in operating cash flow attributable to the new customer joining the system ($225 in year 1).[14]
- The model then sets a line extension allowance to a dollar amount (in this case, $2,900)[15] that results in an IRR calculation of the annual increases in operating cash flow equaling the Company's after-tax weighted average

[11] *See* NW Natural/1802, Taylor.

[12] NW Natural/1802, Taylor/ Tab Financials at cell D85.

[13] *Id*. at cells D86+D87+D88-D91+D95.

[14] *Id.* at cell D97.

[15] *Id*. at cell G73.

cost of capital (in this case, 6.9 percent).[16] The IRR was calculated over 30 years, recognizing both the useful life of utility assets and the expected time a new customer is expected to remain on the system.[17] In other words, an allowance of $2,900 results in an IRR of 6.9 percent over 30 years.

- The result of this calculation is that the allowance is designed to provide a line extension allowance to new customers that, at a minimum, is not financially detrimental to existing customers, as the allowance results in an IRR equal to 6.9 percent by setting the NPV of the cash flows to zero. It should also be noted that the resulting allowance of $2,900 corresponds to a revenue multiplier of 7.8 (i.e., $2,900 / $371 = 7.8).

Q. Have you developed an updated investment analysis to evaluate whether NW Natural's line extension allowance continues to align with these ratemaking principles?

A. Yes. I am submitting an updated version of the model NW Natural provided in response to UG 435 CUB DR 52.[18] With updated assumptions (including but not limited to distribution margin, UPC, cost of capital, and expenses), the line extension allowance for a new residential space heating customer would be $3,790,[19] corresponding to a revenue multiplier of 8.2 (i.e., $3,790 / $461.80 = 8.2). As such, the current line extension allowance of $2,875 continues to provide a net

[16] *Id*. at cell D76.

[17] *Id*. at cell C76.

[18] *See* NW Natural/1804, Taylor.

[19] NW Natural/1804, Taylor/Tab Financials at cell D7.

benefit to existing customers, and represents as revenue multiplier of 6.2 (i.e., $2,875 / $461.80 = 6.2).

Q. What are the assumptions that have been updated?

A. Table 3 summarizes the original inputs and the updated inputs. These updated inputs result in the addition of a new customer providing an economic benefit to the system.

Table 3 – Updated Inputs to Investment Analysis

	2012	**Updated**[20]
After-tax Cost of Capital	6.90%	6.26%
Ann. Margin Revenue	$371	$461.80
Annual Use per Customer	636	532
O&M Expense	$40	$79
Federal Tax Rate	35%	21%
Allowance	$2,900	$3,790

As a result of these updates to key factors, the allowance output in the model increased—which means that there is actually a subsidization occurring from the new customer to existing customers. However, at this time, NW Natural is not seeking a change to its line extension allowance.

IV. REBUTTAL OF CUB WITNESS BOB JENKS

Q. What recommendations does CUB make regarding NW Natural's Construction Allowance?

A. CUB reaches its ultimate recommendation through a two-step process. First, it recommends that the Commission reject the Company's line extension allowance

[20] The "Updated" column uses CUB's UPC estimate of 532, combined with the updated estimates of the inputs used in the 2012 analysis.

framework in Schedule X, and instead use the methodology of 5 years of margin, stating this will reduce the line extension allowance to $2,330.[21] Second, CUB recommends adjusting the revised allowance to account for expected carbon reduction costs (which CUB estimates will be between $4,500 and $5,600), resulting in a negative allowance.[22] Ultimately, they weigh the drastic nature of changing a positive allowance to a negative and "recognize that Oregon has a housing crisis" before they recommend "that the current LEA be reduced to $2,330 through the end of calendar year 2023 to accommodate existing housing projects, then be reduced in 2024 by 50% and be eliminated in 2025."[23]

Q. What are CUB's recommendations relating to incorporating GHG reduction requirements into line extension policies?

A. Mr. Jenks estimates the carbon reduction costs for a new customer over the next 20 years and then recommends NW Natural's line extension allowance fully incorporate these costs.[24] In addition, Coalition witness Burgess cites GHG emission and climate policy as "new concerns [that] have emerged in recent years that suggest the rules and practices for line extensions be revisited."[25]

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[21] CUB/100, Jenks/17.

[22] *Id.*

[23] *Id.*

[24] CUB/100, Jenks/12, line 16.

[25] Coalition/200, Burgess/30, lines 1-2.

Q. What is the status of GHG emissions reduction policies in the State of Oregon?

A. On March 10, 2020, Oregon Governor Brown issued EO 20-04, directing certain state agencies to take specific actions to reduce GHGs and mitigate the impacts of climate change. As a result of EO 20-04, the Oregon Department of Environmental Quality developed rules for a cap-and-reduce program now known as the Climate Protection Program, adopted as OAR 340-271 *et seq*. The CPP places new compliance obligations on local distribution companies, such as NW Natural, on behalf of its customers, to reduce regulated GHG emissions by 50 percent by 2035 and 90 percent by 2050. Under the CPP, the Company acts as the source of compliance for all customers who emit carbon through natural gas consumption. Further, Oregon HB 2021 requires electric utilities to reduce GHG emissions by 80 percent by 2030, 90 percent by 2035, and 100 percent by 2040, from current baseline emissions levels.[26]

Q. Will utility customer costs be directly impacted by compliance with the CPP?

A. Yes. Under the CPP and HB 2021, utility customers will ultimately be responsible for prudently incurred compliance costs for Oregon's electric and gas utilities. These costs will be reflected in the total bills paid by electric and natural gas customers, similar to other pass-through costs such as gas commodity costs or power cost recovery for sales customers. For example, in the Company's most recent Purchase Gas Adjustment, NW Natural began recovering the cost of RNG

[26] ORS 469A.410.

offtake contracts from customers as a pass-through cost spread on an equal cent per therm basis. It is our understanding that the Company would take a similar approach with other CPP compliance costs, such as community climate investments and incremental energy efficiency. With respect to NW Natural's RNG investments, the Company has initially proposed to utilize an automatic adjustment clause and spread the costs of the RNG to all customers on an equal cent per therm basis.

Q. How does customers' incurrence of these compliance costs result in economically efficient outcomes?

A. Insomuch as customers make decisions based on prices, the prices they use to make these decisions will include compliance costs (under the CPP for natural gas utilities and under HB 2021 for electric utilities). If customers weigh the costs of fueling their homes or businesses with electricity or natural gas, they will be on equal footing regarding compliance costs. If one sector can comply with GHG emission reduction requirements less expensively than another, this disparity will be embedded in the costs seen by customers and can influence consumer choices. This leads to more economically efficient outcomes as customers' financial decisions are more fully informed by broader societal implications.

Q. Should CPP compliance costs be incorporated into NW Natural's line extension policy?

A. No. There is no need to incorporate compliance costs in setting the appropriate line extension allowance. These are pass-through costs incurred utility customers, similar to the treatment of gas commodity or power supply costs. While historically line extension allowances were used to incorporate positive or negative externalities in the market through regulation, as discussed above, that is no longer needed for GHG emission reduction costs. With CPP, these costs will no longer be negative externalities but embedded in the costs paid for by all electric and natural gas utility customers. Further, investments and expenses related to CPP compliance are driven by the total GHG reduction requirements and the economics of all compliance projects and are not directly related to any single customer being added to the system.

Q. Do regulatory commissions in general, and the OPUC in particular, acknowledge that extending gas service to new customers can benefit existing customers?

A. Yes. As I stated previously, line extension policies and associated construction allowances are a common element of utility regulation across North America. All utilities have tariff rules, commission-approved methods, and associated internal policies to guide the utility's operational processes when extending service to new customers.

The recent OPUC docket reviewing PGE's line extension allowance (referenced and quoted above) provides an example of how the OPUC acknowledges that line extension allowances are calculated specifically to ensure that the line extension allowance does not result in higher rates. The order also confirms that line extension allowances are a common practice in the utility industry and that most electric utilities have a line extension policy that outlines how costs are allocated and incurred to extend service to new customers.

Q. What commentary does Mr. Jenks provide relating to the relationship between adding new customers and benefits for existing customers?

A. In his testimony, he states:

> Traditionally, it has been assumed that when utilities grow, there is a benefit to customers. Load growth has been associated with allowing the utility to spread its fixed costs across a wider footprint, thereby lowering the rates charged to all customers. It is important to recognize that customers benefitting from load growth is an assumption, not an empirical fact. If this was inherently true, a small utility like Cascade Natural Gas would have higher rates than a larger utility like NWN. However, Cascade's 2020 residential rates were 21% lower than NWN's.[27]

Again, Mr. Jenks's testimony fails to acknowledge that the line extension allowance calculation, by definition, ensures that all customers benefit from new customers joining the system. Therefore, it is not an "assumption", as he states; it is protection embedded in the calculation of the line extension allowance itself.

Q. How do you respond to Mr. Jenks's assertion that if load growth were beneficial, a smaller utility like Cascade would have higher rates than NW Natural?

A. By drawing this conclusion, Mr. Jenks tries and fails to boil down the complex, multifactorial process of setting utility rates to one simple factor, size. Different utilities have different rate designs and rate structures. This is based on several factors, including, but not limited to, embedded and marginal cost structures, cost of capital, current and proposed revenue to cost ratios, age of the utility distribution system, population density of the service territory, customer use profiles, weather,

[27] CUB/100, Jenks/10.

and commodity procurement practices. Cascade and NW Natural certainly differ in these inputs. Attempting to draw any conclusion from Mr. Jenks's comparison is overly simplistic and does not acknowledge the underlying factors that determine utility rates.

What is clear is that commission-approved line extension policies, like NW Natural's, protect existing customers by ensuring that the provision of a line extension allowance to a new customer will not increase rates but instead offer the opportunity for lower rates by, among other things, spreading the system's fixed costs over a larger number of customers.

Q. CUB witness Jenks states that line extension allowances are an exception to the general rule that "[u]tilities are generally required to prove that new capital investments are prudent, based upon information available to the utility at the time it made the investment."[28] Is this an accurate depiction of line extension allowances?

A. Absolutely not. Line extension tariff schedules and associated construction allowances are set by regulatory commissions and, in so much as the utility is accurately reflecting the rules set in the tariff extensions, are prudently incurred. This is no different from trackers, riders, investment plans, or other regulatory actions that set the boundaries of prudent utility actions, while not requiring every purchase order or work order to receive commission approval. Commissions review and approve the methods embodied in line extension policies, which

[28] CUB/100, Jenks/14.

ensures the utility can act prudently in application of the tariff. It would be unreasonable to expect a commission to conduct a prudence review for each individual extension project; this is exactly why commissions use line extension policies to direct actions and set the boundaries of reasonableness.

In fact, in his own testimony in this proceeding, Mr. Jenks includes the following quote on how the Commission described line extension allowances to the Oregon Legislature in 2016:

> The natural gas utilities decide whether to build pipelines and extend their distribution systems into unserved areas, subject to the PUC's review. The utilities also establish their own distribution policies, which the PUC reviews and approves to help ensure the rates paid by all ratepayers for these extensions are fair, just and reasonable.[29]

He goes on to say that the line extension allowance has since changed (in terms of how the allowance is calculated)[30] but does not contend that there has been any change in the requirement for OPUC approval.

Q. How are the line extension allowances utilized to offset construction costs recovered by NW Natural?

A. Construction costs not collected from the customer are capitalized and added to NW Natural's cost-of-service. NW Natural includes these capitalized costs in its rate base and requests recovery in a future general base rate case filing. These costs are not automatically recovered from ratepayers. Instead, they are reviewed during general base rate case filings.

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[29] CUB/100, Jenks/15, lines 15-20.

[30] CUB/100, Jenks/16-17.

Q. What does CUB witness Jenks calculate for the years of margin required to recoup the costs of adding a single customer to NW Natural's system?

A. On page 12 of his testimony, Mr. Jenks includes the following table:

Figure 1 - Jenks's Table 1

Table 1

Cost Associated with a Single New Customer	Cost	Years of Margin
GHG Reductions	$4519 - $5648	11 - 14
Line Extension Allowance (LEA)	$2,875	7
Financing cost of LEA	$1,907	5
total	$9300 -$10430	23 - 26 years

According to his calculations, it will take between 23 and 26 years to recover the cost of adding a new customer to the system.

Q. Is the calculation methodology used by Mr. Jenks correct?

A. No. My critique of Mr. Jenks's methodology falls into four categories:

- <u>Category 1 - CPP Compliance Cost</u>: When a new customer joins the system, its usage and associated emissions are treated in the exact same way as existing customers for purposes of achieving CPP compliance. To achieve compliance with the CPP, emissions must be reduced by 50 percent from current levels by 2035.[31] Therefore, a new customer and an existing customer must bear the same cost of compliance (relative to usage) each year. Mr. Jenks asserts that the new customer is responsible for

[31] Emission reductions are set to increase each year and not set to 50 percent in the first year of compliance. As such, each year a greater portion of consumption must be offset by lower GHG emissions.

compliance costs associated with 100 percent of its usage in year 1, while existing customers are only responsible for covering the cost of reducing usage by 50 percent by 2035. His approach is inconsistent with the fundamental regulatory principle that cost responsibility should follow cost causation, results in intergenerational inequities, and breaks the matching principle of regulation—that costs be matched to the period that benefits from the costs being incurred and be recovered from customers in that period.

Under CUB's proposal, the full cost of CPP compliance would be baked into the line extension allowance (or lack of a line extension allowance if it is moved to $0) provided by a new customer. That same customer (or any other customer who may move into that house in the future) would then have to pay the entire amount of CPP compliance AGAIN through rates for decades. This is double-counting and unfairly punitive to new gas customers.

- <u>Category 2 – Revenue Multiplier Calculation</u>: On page 12 of his testimony, Mr. Jenks states that based on his assumptions, the revenue multiplier for a $2,875 LEA is 7.28 years.[32] This is based on an assumed usage of 532 therms per year, resulting in an annual margin per residential customer of $394.74.[33] As shown in Table 3 above, using updated assumptions with a

[32] CUB witness Jenks shows in his Table 1 7 Years of Margin which is 7.28 when dividing $2,875 by $394.74.

[33] CUB witness Jenks utilizes the projected usage NW Natural included in its CPP compliance modeling for the year 2035.

UPC of 532 therms per year results in annual margin per residential customer of $461.80. This represents a multiple of 6.23, which is lower than the 7.28 years presented by Mr. Jenks.

- Category 3 - Attrition Assumptions: On page 13 of his testimony Mr. Jenks states:

> If the customer installs a heat pump and leaves NWN's system after 20 years, there will also be stranded costs associated with the line extension that have not yet been recovered. The system loses money on this customer.[34]

As explained above, this is simply not the case. The cumulative margin associated with adding a new customer to the system exceeds the LEA within seven years (6.23 years). If a customer decides to install a heat pump in 20 years, the benefit from adding that customer to the system will outweigh the cost of the LEA by a factor of three (20 / 6.23 = 3.21x). Furthermore, it is not a forgone conclusion that a customer adding a heat pump means a customer leaves the gas system entirely. It is possible, if not likely, that a customer will replace an existing gas furnace with a new higher-efficiency gas furnace, or continue to use gas as a backup heating source or for use in other appliances, in which case all other customers continue to benefit from this customer contributing revenues to cover common costs.

- Category 4 - Double Counting of Financing Costs: In Table 1 on page 12 of his testimony, Mr. Jenks details his view of the costs associated with a

[34] CUB/100, Jenks/13, lines 4-6.

single new customer. In this Table 1, Mr. Jenks includes the "Financing Cost of the LEA" with a value of $1,907, or five years of margin. The actual financing cost of this is already netted against the new customer margin in the calculation used to determine the "Line Extension Allowance (LEA)" in row 2 of Table 1. Including it again as a separate row in Table 1 is double counting.

Q. Is Mr. Jenks accurate in his statement, "[i]f a new customer stays on NWN system for 20 years, the margin contribution that customer makes is not enough to pay for the GHG emission reductions associated with that load . . . "?[35]

A. No. As described above in this section, NW Natural has proposed recovering CPP compliance costs through rates on a per-therm charge. This is similar to how costs for RNG are recovered, creating a "one-for-one" revenue offset for an expense. The estimated margin used by Mr. Jenks does not contain revenues associated with CPP compliance or gas commodity costs. Given Mr. Jenks's perspective, a customer's margin revenues will also not cover their gas commodity costs, which is also an erroneous and meaningless conclusion.

Q. What is the result of CUB witness Jenks's proposal to include the cost of CPP compliance in calculating the line extension allowance?

A. CUB witness Jenks's proposal is to include 100 percent of the forecasted long-term marginal average costs as costs directly attributable to the incremental

[35] CUB/100, Jenks/13, lines 1-3.

customer. He ignores the fact that the investments and expenses related to CPP compliance are driven by the total GHG reduction requirements and the economics of all compliance projects are not directly related to any single customer being added to the system. Including all of the CPP compliance costs over the life of the customer in their line extension allowance calculation results in customers unable to connect to the system unless they pay the customer contribution required that would include all of their incremental direct costs. As such, Mr. Jenks's proposal to include compliance costs in calculating the line extension allowance results in the requirement for new customers to pay 100 percent of their compliance costs upfront for 20 years of usage. They will also pay 100 percent of the actual average compliance costs paid for by all customers as they consume natural gas. This is an unreasonable position that is contrary to the principle of fairness and equity in ratemaking. New customers should not have to be responsible for emissions reductions fully when they connect to the system and then in perpetuity for all other customers. If Mr. Jenks's recommendation were accepted, and there is a requirement for new customers to pay 100 percent of their compliance costs over 20 years on the day they were connected for usage, then they should be exempt from paying the average costs for all other customers' compliance costs.

Q. Is it a reasonable ratemaking approach to have customers pay for 20 years of costs upfront?

A. No. I can think of no regulatory precedent, ratemaking principle, nor tariff provisions across North America that require new customers to pay for estimated operating costs prior to them becoming customers. This is also antithetical to the principle of rate regulation to ensure productive outcomes of monopoly utilities by aiming to replicate outcomes that occur in the competitive markets. I am unable to present a competitive market or commercial enterprise within competitive markets that would charge new customers operating costs estimated to occur throughout years of service. In fact, if a competitive enterprise did this, another enterprise would realize they can charge the expenses incrementally as the service is consumed, quickly gaining market share and putting the first enterprise out of business.

Furthermore, placing the full burden of compliance on new customers for 20 years of usage before they receive service would expose these new customers to risks associated with their actual consumption being lower than estimated and future CPP compliance costs being lower than expected (i.e., they paid for more than they should as actual usage and costs were realized), while simultaneously exposing existing customers to risks that either or both new customer consumption and future CPP compliance costs would be higher than estimated (i.e., new customers paid less so existing customers have to pay more). In addition to this resulting in undue discrimination, this concept would be administratively burdensome, costly to implement and monitor, and would lead to significant customer dissatisfaction and confusion.

Q. What does Mr. Jenks assume to be the useful life of a new gas furnace?

A. In his testimony, Mr. Jenks states that "[t]he useful life of a gas furnace is generally considered to be 15 to 20 years."[36] He cites the website of an HVAC contractor named A-1 Mechanical as his source. Based on the link provided in footnote 26 on page 16 of his testimony, A-1 Mechanical appears to provide residential HVAC service in the Lansing and Grand Rapids, Michigan areas. It is a factory authorized dealer for one brand of furnaces (Carrier), and the useful life it estimates on its website is actually for units installed "in the Lansing, MI or Grand Rapids, MI area".[37]

As explained on its own website, how often the furnace is used is one of the main factors that determine the furnace's useful life, stating:

> Unfortunately, homeowners in the Lansing, Michigan, area don't often have the luxury of foregoing heating system use during the winter months. Here in the northern part of the country, furnaces and heating systems operate nearly around the clock during the cold season – unlike in the South, where homeowners may only have to use their heating systems sparingly. Compared to furnaces in the South, homeowners in the North can typically expect a shorter gas furnace lifespan.[38]

While Oregon is not the South, it does have a very different heating profile than the Lansing and Grand Rapids, Michigan areas, so it follows that the expected useful life of a new natural gas furnace in Oregon will be longer than one in Michigan.

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[36] CUB/100, Jenks/16, lines 21-22.

[37] A-1 Mechanical, *What Is the Average Lifespan of a Gas Furnace?* (https://a1mechanical.com/gas-furnace-lifespan/) (visited June 3, 2022).

[38] *Id*.

Q. What is the average useful life of a new gas furnace?

A. On January 17, 2017, Commission Staff submitted (in docket UM 1565) the results of Energy Trust's third-party economic analysis (conducted by SBW Consulting Inc.) comparing the residential use of gas furnace systems to heat pump systems.[39] As shown in Table 1 (page 4 of SBW's report), the effective useful life of a new gas furnace is estimated to be 25 years. For another data point, the US Energy Information Administration ("EIA") estimates the useful life of a new gas furnace to be between 16 and 27 years.[40]

Q. Did you also update the investment analysis presented in Section III with a shorter time period?

A. Yes, for illustrative purposes, the investment analysis presented in Exhibit NW Natural/1804, Taylor was updated for a 20-year time period and to include the UPC of 532 therms/year used by Mr. Jenks's in CUB/105 Jenks/1. This resulted in an allowed investment of $3,200 (representing a 6.93 multiple of margin revenue), which exceeds the current line extension allowance of $2,875.

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[39] Staff Report, Docket UM 1565 (Jan. 17, 2017) (available at: https://edocs.puc.state.or.us/efdocs/HAU/um1565hau1162.pdf).

[40] U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2022: Residential Demand Module*, at 7 (Mar. 2022) (https://www.eia.gov/outlooks/aeo/assumptions/pdf/residential.pdf).

V. REBUTTAL OF COALITION WITNESS ED BURGESS

Q. What recommendations does the Coalition witness Mr. Burgess make regarding NW Natural's Construction Allowance?

A. Mr. Burgess states his "primary recommendation in this case is for the Commission to order NW Natural to reduce its line extension allowances to $0."[41] His recommendation applies to both residential and non-residential customers. In the absence of the Commission accepting this recommendation, he recommends that "the allowance calculation should be modified to reflect more reasonable assumptions (i.e., a payback period of fewer than 30 years; Washington set its investment period at 7 years, for example)."[42]

Q. Coalition witness Ed Burgess cites the recent review of line extension allowances conducted by the WUTC. Can you please describe that proceeding?

A. In 2021, the WUTC requested comments from interested stakeholders regarding whether natural gas utilities should continue to use the Perpetual Net Present Value ("PNPV") methodology to calculate natural gas line extension allowances.[43] The WUTC's Order in that proceeding required each gas utility that employed the PNPV methodology (NW Natural does not) to use a Net Present Value ("NPV") of

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[41] Coalition/200, Burgess/29.
[42] *Id.*
[43] *See In re Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology to Calculate Natural Gas Line Extension Allowances*, WUTC Docket No. UG-210729.

seven years.[44] For example, Puget Sound Energy noted in its Compliance Filing that the NPV methodology reduced its line extension allowance from $4,328 to $1,997.[45] Importantly, the WUTC concluded that the change to the line extension allowance was an "interim measure" while the WUTC "continue[s] to engage in dialogue with regulated utilities and other stakeholders in Docket U-210553, the [WUTC's] broader examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state targets."[46] In other words, the WUTC did not rashly eliminate line extension allowances for gas utilities, and instead, will continue to evaluate the issue while it completes an economy wide decarbonization study.

Q. Was NW Natural required to file a revised construction allowance with the WUTC?

A. No. NW Natural does not rely on the PNPV methodology in Washington (or Oregon), so they were not required to make any changes to their allowance.

Q. How does Coalition witness Mr. Burgess characterize the provision of a line extension allowance for new, non-residential customers?

A. Mr. Burgess states that "[i]n both the residential and non-residential cases, the line extension allowances amount to a cross-subsidy."[47] He further asserts that "in the

[44] *In re Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology to Calculate Natural Gas Line Extension Allowances*, WUTC Docket No. UG-210729, Order No. 01 at 8 (Oct. 29, 2021).

[45] *In re Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology to Calculate Natural Gas Line Extension Allowances*, WUTC, Docket No. UG-210729, Puget Sound Energy Compliance Filing at 1 (Nov. 17, 2021).

[46] Docket No. UG-210729, Order No. 01 at 6.

[47] Coalition/200, Burgess/6, lines 13-14.

case of non-residential customers the amount of cross-subsidy appears to be unlimited, which I believe is inappropriate and not reasonable."[48]

Q. Is the provision of a line extension allowance to a new gas customer a cross-subsidy?

A. No. A cross-subsidy exists when a company artificially lowers prices for one group of customers by charging higher prices to another group. The calculation of NW Natural's line extension allowance, which is based on a comparison of incremental revenues to incremental costs, specifically ensures that existing customers are not required to contribute to the cost of the addition of new customers. Therefore, it cannot be considered a cross-subsidy. Mr. Burgess neglects to point out that the new customer is responsible for paying for incremental costs through current rates, including the revenue requirement associated with any construction allowance they received.

Q. Is the line extension allowance provided to new, non-residential customers unlimited, as Mr. Burgess states?

A. Clearly not. The line extension allowance provided to new, non-residential customers is determined by a discounted cash flow ("DCF") calculation that limits the allowance to an amount that ensures the addition of the new customer results in a net benefit to existing customers over the time period evaluated in the DCF model.

[48] Coalition/200, Burgess/6, lines 20-22.

Q. Does Mr. Burgess estimate the line extension allowance costs NW Natural could incur in 2022 and 2023, and if so, how does he relate this to the total requested increase in this case?

A. Yes. On page 11 of his testimony, Mr. Burgess states:

> …assuming the 2021 costs discussed above are representative of future years, NW Natural could incur $51.6 million in allowance costs in 2022 and 2023. I estimate that this could equate to $4.1 million of the requested $73.5 million increase in revenue, or about 6% of the total request. Thus if no allowances were provided going forward, I believe the Company's requested increase could be reduced by approximately 6%.[49]

This appears to be calculated as the "Total" row of the "Allowance" column in Mr. Burgess's Table 1 ($25,789,270) multiplied by two (since his estimate is for 2022 and 2023).[50]

Q. Do you agree with Mr. Burgess that if no allowances were provided going forward, the Company's requested increase could be reduced by approximately six percent?

A. No. Mr. Burgess's logic completely ignores the economic benefit of adding new customers to the system. Mr. Burgess estimates that adding new customers would create a net cost of $51.6 million in 2022 and 2023. As I explain in detail in Section III above, the line extension allowance is determined through a calculation that ensures no economic detriment to existing customers. Therefore, the allowance ($51.6 million in the example proffered by Mr. Burgess) would, at a minimum, be offset by the incremental distribution margin associated with new customers. If no

[49] Coalition/200, Burgess/11, lines 14-19.

[50] Coalition/200, Burgess/10.

allowances were provided, the Company's requested rate increase would not necessarily be reduced by approximately six percent. On the contrary, if fewer customers are added to NW Natural's system due to no allowances, existing customers would not benefit from economies of scale and the recovery of common costs across more customers. Even with a corresponding lower level of growth-related rate base, this could lead to an increase in the requested revenue requirement due to lower levels of current revenues, not a decrease as erroneously projected by Mr. Burgess.

Q. How does Mr. Burgess attempt to apply the concept of cost causation to NW Natural's line extension policy?

A. Mr. Burgess states:

> In the case of a newly connecting customer, under the principle of cost causation, 100% of the new service line costs incurred would be attributable to that customer as the 'cost causer'. If gas system costs were assigned purely based on the principle of cost causation or "beneficiary pays" there would be no need to provide any allowances, and likely no need for a Schedule X. Under such a hypothetical scenario, 100% of the costs would be assigned to that new customer.[51]

Q. Is Mr. Burgess's application of the concept of cost causation to line extension policy appropriate?

A. No. While the concept of cost causation provides important guidance for allocating a utility's embedded costs, Mr. Burgess's application to line extension allowances creates distortions between customers. Mr. Burgess's conclusion fails to recognize that new and existing customers pay base rates, including the recovery

[51] Coalition/200, Burgess/12, lines 16-21.

of annual revenue requirements associated with capital projects. A gas utility's existing rates are not designed on an individual customer basis—they are designed on a class average basis. The common fixed costs of providing utility service to a particular rate class are attributed to all customers within the class—not to any one customer—resulting in average rates reflecting average costs of providing service. If, as Mr. Burgess suggests, all these costs were allocated directly to and paid for by each customer when connecting to the distribution system, they would be paying the average costs for everyone and the direct costs for themselves. Under this scenario, the gas utility's new customers would be held responsible for all of their capital-related costs while also paying the average annual revenue requirement associated with all customers' capital-related costs. This cross-subsidization of existing customers by new customers is an unreasonable outcome that does not result in fair and equitable treatment of new and existing customers.

Q. What does Mr. Burgess say about the benefits other customers enjoy when a new customer is added to the system?

A. In his testimony, Mr. Burgess states:

> Encouraging customer growth and subsequently increasing sales can put downward pressure on rates for all customers by spreading the fixed cost of the distribution system over a larger customer base. However, this is only true once the initial investment in the line extension has been recouped. Notably, in NW Natural's case, the estimated payback period for most line extensions allowances is up to 30 years. [Internal footnote 6] This means that any potential financial benefits conferred to other customers would not materialize until 30 years after the line extension allowance is granted.[52]

[52] Coalition/200, Burgess/15, lines 14-20.

Footnote 6 in this quote references NW Natural's response to CUB DR 52, which contains an attachment (UG 435 CUB DR 52 Attachment 1.xlsx) that provides a DCF model from which residential construction allowances were estimated.

Q. How does Mr. Burgess determine that "the estimated payback period for most line extensions allowances is up to 30 years"?

A. There is no nexus between the material Mr. Burgess references in his testimony and his conclusion that the estimated payback period for most line extension allowances is up to 30 years. At the end of the sentence referencing a payback period of 30 years, Mr. Burgess cites NW Natural's response to CUB DR 52 (which he included as Exhibit Coalition/213 of his testimony). CUB DR 52 reads:

> Refer to NW Natural Oregon Tariff Book Schedule X, please provide the workpapers used to estimate the Category A-D construction allowance for residential customers.[53]

In its response, NW Natural stated:

> For Category A in the tariff, the revenue stream was assumed for 30 years; for Category B, the revenue stream was assumed for 15 years, and for Category C, the revenue stream was assumed for 5 years. The 30-, 15-, and 5-year terms were used based on an assumption that a customer having gas space heating would remain a customer for 30 years, and so on.[54]

In reviewing the DCF analysis in UG 435 CUB DR 52 Attachment 1.xlsx, I can only assume that Mr. Burgess misinterpreted the fact that the DCF analysis was calculated over 30 years (recognizing both the useful life of utility assets and the expected time a new customer is expected to remain on the system) and reached

[53] Coalition/213, Burgess/1.

[54] *Id.*

the erroneous conclusion that it would take 30 years for existing customers to start benefitting from a new customer being added to the system.

Q. How does Mr. Burgess recommend modifying the allowance and how it is calculated?

A. Mr. Burgess states that if the Commission does not reduce the allowance value to $0 he recommend the allowance calculation should be modified to reflect more reasonable assumptions.[55]

Q. Have you updated the allowance calculation with modified assumptions?

A. Yes. As demonstrated in response to Mr. Jenk's testimony in Section IV, the investment analysis presented in Exhibit NW Natural/1804, Taylor was updated for a 20-year time period and to include a lower UPC of 532 therms/year. This resulted in an allowed investment of $3,200 (representing a 6.93 multiple of margin revenue), which exceeds the current line extension allowance of $2,875.

Q. What portion of the Draft Report in the Natural Gas Fact Finding proceeding did Mr. Burgess cite in his testimony?

A. Mr. Burgess cited the following excerpt:

> PUC Rates, Finance, and Audit (RFA) staff and Oregon Department of Justice are to explore with gas and electric utilities an interim, easily implemented approach to line extension allowance policy in future upcoming gas and electric rate case dockets that reflects the benefits, costs, and risks associated with system growth or improvements relative to the state's policies on decarbonization.[56]

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[55] Coalition/200, Burgess/29, lines 11-14.

[56] Coalition/204, Burgess/28.

Q. Please explain how the citation should be interpreted in setting NW Natural's line extension allowance.

A. As discussed in Section II of this testimony, there are several methods recognized by the utility industry for determining appropriate levels of line extension allowances. In Oregon, revenue multipliers and investment analyses have been used to set and evaluate line extension allowance for groups of customers and specific projects. I believe these remain viable as easily implemented approaches to setting line extension allowances. Unfortunately, relying on approaches presented by CUB and the Coalition results in manipulating line extension allowances in ways that do not reflect the underlying economics of a utility's system or cost structures. However, the historical negative externality of GHG emissions is now incorporated in the prices borne by both gas and electric utility customers and are no longer external to customers' evaluation of using natural gas. These historically external public costs associated with GHG emissions will no longer be external as they will be incorporated into the cost borne by each customer. As such, there is no need to subjugate line extension allowances with these non-economic considerations. Introducing a layer of specific stakeholder-driven, subjective interpretations into regulatory outcomes can discourage some prospective customers from using natural gas when it would be economical and socially beneficial for them to do so. Further, all customers, new and existing, should equitably contribute to the societal benefits obtained from decarbonization through the cost of compliance.

Q. Mr. Burgess states that his recommended $0 allowance may contribute to "some new customers opting for electric appliances instead of gas. In fact, this outcome may also be desirable since it would be highly consistent with the state's overall climate and greenhouse gas policy goal."[57] What is your response to this claim?

A. As an initial matter, Mr. Burgess provides no support for his claim that a choice of electric service over natural gas is "highly consistent" with the State's climate and GHG policy goals, which is an issue addressed in Ms. Heiting and Mr. Bracken's Reply Testimony.[58] Second, Mr. Burgess follows this statement with:

> I acknowledge that these benefits might come with a tradeoff. However, I am not convinced that a modest -- and frankly uncertain -- reduction in rates 30 years from now is sufficient justification to forego the other benefits I describe here.[59]

Aside from erring in stating that the reduction in rates is over a 30-year period, which I address earlier in Section V, this perspective fails to account for the private benefits customers enjoy from the consumption of natural gas. While Mr. Burgess may recognize that these benefits may come with a tradeoff, he fails to weigh the tradeoff for customers who, under his proposal, would see significant barriers to using natural gas for their residences and businesses. As described below, weighing these private tradeoffs for each consumer would require detailed knowledge of individual consumer preferences. I am unable to imagine how the

[57] Coalition/200, Burgess/28.

[58] NW Natural/1700, Heiting-Bracken.

[59] Coalition/200, Burgess/28.

data needed for such insights would be obtained and reviewed by Mr. Burgess or this Commission. It is best to leave the balancing of consumer preferences to prices, where those prices are informed by the relative cost of reducing GHG emissions for both natural gas and electric utilities.

Further, Mr. Burgess also fails to recognize that the use of electric appliances also requires paying costs to comply with Oregon's GHG reduction goals (through HB 2021). The markets should decide the least expensive method of reducing GHG emissions through interactions between market participants based on price signals that incorporate costs and externalities, not through a line extension policy. Suppose one fuel source can less expensively comply with the CPP over time. In that case, this will be reflected in future rates and costs, but prematurely deciding an outcome and setting rates and prices to effectuate that outcome results in inefficient, misplaced price regulations—this type of deterministic regulation results in a self-fulfilling prophecy. Where a presumption is used to set relative costs, customers make decisions based on these relative costs, and the presumption is ultimately realized—not due to its inherent accuracy but due to the regulations that impact consumer behavior.

Q. What "flaws" does Mr. Burgess find with the rationale for providing new customers line extension allowances?

A. Mr. Burgess does not believe that line extension allowances are appropriate because "there is no evidence that new service line costs are an economic barrier to new customers connecting to the gas system."[60] To support this assertion, he uses information provided by NW Natural in its response to Coalition DRs 24 and 100 to make two points. First, he states that "[t]his means that at least 27% of new customers had no problem covering the service line extension costs, even though they did not receive a subsidy under Schedule X."[61] Second, he states:

> Moreover, as Coalition DR 24 shows, some residential service line extension costs in 2021 were as high as $40,517. Even if this customer received the maximum allowance of $2,875, they still would have had to pay a customer contribution of over $37,000 and yet decided to connect anyways. In such instances, it is not clear that the existence of a relatively small allowance is a determining factor for unlocking new customer revenue.[62]

Q. How do you respond to his first of the two assertions?

A. As shown in Table 4 below, for residential customers in Oregon, only 30 (or 0.43 percent of the total) did not receive an allowance. Customers who do not get an allowance are those that did not bring a large enough load (based on appliance) to cover the investment.

Table 4 – Residential Customer Count by Allowance Amount

Allowable	Count	% of Total
$2,875	6,033	87%
$2,100	603	9%
$850	55	1%
$0	30	0.43%
Other	193	3%
Total	6,914	100%

[60] Coalition/200, Burgess/23, lines 13-14.

[61] *Id.* at 23, lines 19-21.

[62] Coalition/200, Burgess/23-24, lines 21-3.

Q. How do you respond to his second of the two assertions?

A. In its response to Coalition DR 24, NW Natural provided a histogram with the number of residential customers added in 2021 broken out (in $500 increments) by the total cost NW Natural incurred to build a new service line to connect a new residence to gas utility service. While one new service line cost $40,517, the total number of new service lines costing greater than $15,000 totaled 50, representing 0.52 percent of the 9,589 new residential service lines added in 2021. The data points Mr. Burgess cites do not support his claim that "there is no evidence that new service line costs are an economic barrier to new customers connecting to the gas system."[63]

Q. Based on your responses to the previous two questions, does Mr. Burgess's analysis support his assertion that there is no evidence that new service line costs are an economic barrier to new customers connecting to the gas system?

A. No. On the contrary, Mr. Burgess states that customers may decrease their use of natural gas— "I could envision a $0 allowance being a contributing factor towards some new customers opting for electric appliances instead of gas."[64]

Mr. Burgess's arguments are inconsistent. On the one hand, he says the extensions are not an economic barrier, but on the other hand, he states that moving the allowance to $0 could result in customers opting for electric appliances.

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[63] Coalition/200, Burgess/23, lines 13-14.

[64] Coalition/200, Burgess/28, lines 4-5.

His argument is fundamentally flawed as it is based on two distinct beliefs (1) customers have no response in demand if the allowance is moved from $2,875 to $0, and (2) moving the allowance from $2,875 to $0 will result in customers choosing electric appliances instead of gas. Mr. Burgess can't have it both ways.

Q. What is the likelihood a customer will pay all construction costs if there is no allowance?

A. A customer's appetite for paying for a service extension is unknown by anyone other than the customer. Luckily, this information is not needed to set appropriate regulatory policies for line extension allowances. They can be set on an economic basis. A consumer's preference is informed by the individual customer's desire to utilize natural gas based on: estimated benefits, relative costs of equipment and other services, budgetary constraints for that customer, emotional and moral qualms, and amount of time and energy they spent to reach an informed decision. In other words, if a customer does not want natural gas used in their home, they can make that choice. Fortunately, it is not necessary for individual customer preferences to be known by a regulatory commission to set appropriate line extension allowances. They can be set based on an economic basis ensuring fairness between existing and new customers. As mentioned above, with the implementation of CPP and HB 2021, the costs of GHG emission reductions will no longer be an externality to electric and natural gas markets in Oregon. There is now a much better alignment between individual customer preferences and decisions and the societal costs of those decisions.

Q. What does Mr. Burgess state about the availability/affordability of alternatives to natural gas?

A. In his testimony, Mr. Burgess cites "[a]vailability/affordability of alternatives" as one of the factors supporting a lower level of allowances/subsidies.[65] He states that "[r]ecent studies have shown that electrification has become increasingly cost competitive when compared to gas."[66]

Q. What studies does Mr. Burgess use to support his assertion that "electrification has become increasingly cost competitive when compared to gas"?

A. Mr. Burgess only cites one study by the Rocky Mountain Institute titled "The New Economics of Electrifying Buildings: An Analysis of Seven Cities." Mr. Burgess states that the report:

> compared the net present costs of "a new all-electric home versus a new mixed-fuel home that relies on gas for cooking, space heating, and water heating" in several major cities across the country, including the Pacific Northwest. The study found that all-electric homes were the cheaper option in every instance. Below is a summary of the study's findings for Seattle, which should be broadly applicable in the Pacific Northwest.[67]

The results of this study claim that in Seattle, a new all-electric home versus a new mixed fuel home that relies on gas for cooking, space heating, and water heating saves $4,300 in net present costs and 28 tons of CO2 emission over 15 years.[68]

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[65] Coalition/200, Burgess/20.

[66] Coalition/200, Burgess/20, lines 2-3.

[67] Coalition/200, Burgess/20, lines 3-8.

[68] Coalition/200, Burgess/20.

Q. Are the study's findings for Seattle broadly applicable to Oregon as a part of the Pacific Northwest, as stated by Mr. Burgess?

A. No. According to its website, in 2005, Seattle City Light became the first electric utility in the country to achieve zero net greenhouse gas emissions and has maintained that carbon neutral status every year since. The City of Seattle's website also states:

> "City Light uses hydroelectric resources for most of the power we provide, which is one reason our greenhouse gas emissions are so low."[69]

In fact, according to its 2020 Integrated Resource Plan, the City's power supply mix is comprised of at least 94 percent carbon-free resources (84 percent hydro, five percent nuclear, four percent wind, and one percent biogas).[70]

By contrast, the resource portfolios of Oregon's two largest electric utilities are dominated by fossil fuels. As a result, electric utility customers will bear significant costs associated with decarbonization. Therefore, it is not appropriate to assume that the costs to electrify homes in Seattle are comparable to the costs to electric homes in, for example, Portland, Oregon.

For a detailed discussion of building load decarbonization pathways for gas and electric utilities in Oregon, please refer to the Reply Testimony of Kimberly Heiting and Ryan Bracken, NW Natural/1700.

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[69] Seattle City Light, *Climate Change Response* (http://www.seattle.gov/city-light/energy-and-environment/environmental-stewardship/climate-change-response) (last visited June 3, 2022).

[70] Seattle City Light, *2020 Integrated Resource Plan Progress Report*, at 12 (2020) (available at: http://www.seattle.gov/documents/Departments/CityLight/2020IRPProgessReport.pdf).

Q. What information does Mr. Burgess provide to support his claim that natural gas prices have both increased and experienced substantial volatility?

A. Mr. Burgess states that:

> The supply of gas and associated commodity prices were low and relatively stable in the 2012 timeframe when NW Natural's line extensions allowances were last updated. However, in the last few years, gas prices have both increased and experienced substantial volatility.[71]

Then he provides a chart showing the NW Spot Natural Gas Index prices from April 2019 through April 2022.[72]

Q. Is this a fair depiction of natural gas commodity prices and their impact on customers?

A. No. First, natural gas utilities utilize a full portfolio of upstream resources to mitigate daily price volatility, including storage assets, needle peaking facilities, and upstream supply contracts. It is also worth noting that while Mr. Burgess references the last time NW Natural's line extension allowances were updated (2012) as a reference point, he then only shows the last four years (since April 2019) of data in his chart. Furthermore, he does not overlay data on electricity prices, which is necessary to draw a valid comparison.

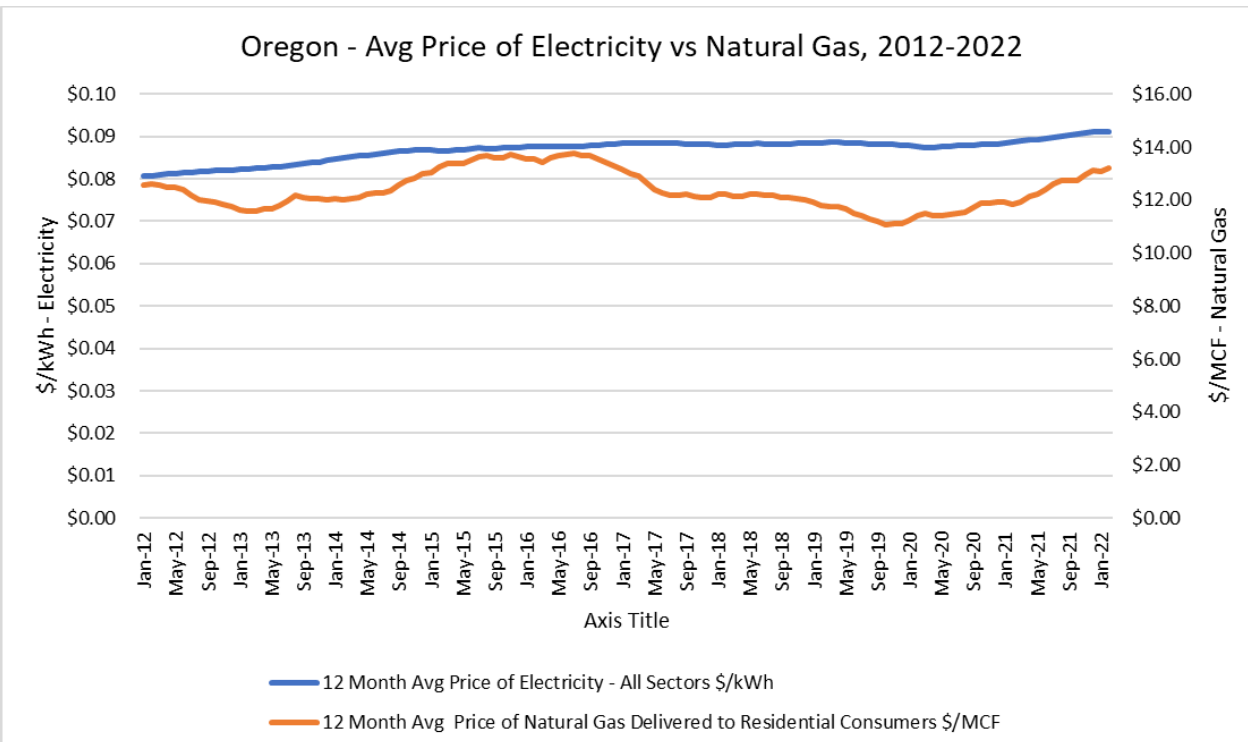
[71] Coalition/200, Burgess/16, lines 21-24.

[72] Coalition/200, Burgess/17.

Q. How does the cost of natural gas compare to electricity over time in Oregon?

A. Table 5 compares the delivered cost of natural gas to residential customers in Oregon to the retail price of electricity in Oregon over the last ten years (since 2012, when NW Natural's line extension allowance was last updated).

Table 5 – Natural Gas vs. Electricity Prices[73]



By changing the timeframe to the relevant inflection point noted by Mr. Burgess and overlaying electricity prices it is clear that: (1) the delivered cost of electricity has increased at a greater rate than the delivered cost of natural gas in Oregon,

[73] Source: U.S. Energy Information Administration.

and (2) the delivered cost of natural gas in Oregon does not display a significant rate of volatility.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. What recommendations do you make to this Commission concerning CUB's and the Coalition's testimony advocating for drastic decreases to and fully dismantling NW Natural's line extension allowance?

A. I recommend no changes to NW Natural's line extension allowances or to Schedule X. Updating the line extension allowance investment analysis results in a higher allowance than the current allowance of $2,875, and as such, the current allowance continues to provide economic benefits to existing customers. The sweeping changes recommended by CUB witness Jenks and Coalition witness Burgess are misguided, rely on faulty economics, are based on incorrect interpretations and incorrect assumptions, and fail to satisfy fundamental regulatory principles. Line extension policies and allowances similar to NW Natural's are used extensively by utilities across North America. NW Natural's line extension policy and the construction allowance provided to new customers:

- Provides net benefits to existing customers by reducing the rates they pay relative to what they otherwise would pay had service not been extended to new customers;
- Is based on analyses that protect existing customers, ensuring there is no subsidy to new customers at their expense; and
- Is subject to review by the OPUC and therefore, subject to the same prudence standard as other utility capital investments.

With the implementation of the CPP and HB 2021, the costs of GHG emission reductions will no longer be an externality of electric and natural gas markets in Oregon. CPP compliance costs are recovered directly from customers and should not be considered in NW Natural's line extension allowance calculation. Doing so would result in double counting of the associated cost responsibility, would counter the fundamental regulatory principles of cost responsibility following cost causation, and would represent discriminatory pricing between customers. The investments and expenses related to CPP compliance are driven by the total GHG reduction requirements and the economics of all compliance projects and are not directly related to any single customer being added to the system.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibits of John D. Taylor

LINE EXTENSION POLICY
EXHIBITS 1801-1804

June 6, 2022

EXHIBITS 1801-1804 – LINE EXTENSION POLICY

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PUBLIC UTILITY COMMISSION OF OREGON

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Exhibit of John D. Taylor

LINE EXTENSION POLICY
EXHIBIT 1801

June 6, 2022

ATRIUM ECONOMICS
CENTERED ON ENERGY

John D. Taylor

Managing Partner

Mr. Taylor is a utility pricing expert with experience developing cost of service studies for both electric and gas utilities and transmission companies. He has deep experience with developing residential and commercial rates, analyzing midstream transportation and storage capacity resources, and assessing the relationship between price signals and the adoption of distributed generation assets.

He has filed testimony as an expert witness on class cost of service studies for both electric and natural gas utilities, return on equity, and on the appropriate use of statistical analysis during audit testing. Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. He has an expert knowledge of cost allocation principles for utility cost of service studies and for affiliate transaction and service agreements. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He has also been involved in the sale of generating assets as sell side advisors, supporting due diligence efforts, financial analyses, and regulatory approval processes.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

16

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

United States

- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

Canada

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed distributed CNG/LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of John D. Taylor

LINE EXTENSION POLICY
EXHIBIT 1802

Part of this exhibit is being filed in its native, Excel format.

June 6, 2022

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 CUB DR 52

52. Refer to NW Natural Oregon Tariff Book Schedule X, please provide the workpapers used to estimate the Category A-D construction allowance for residential customers.

Response:

Please see attached file named "UG 435 CUB DR 52 Attachment 1.xlsx." Note that this file produced the construction allowances as filed in the general rate case UG-221, and not the allowances that are quantified in Schedule X of the tariff. The changes that were proposed in the Company's filing in UG 221 were approved in Order 12-408 (page 8), which adopted the Second Partial Stipulation in the docket. Order 12-408 is attached as "UG 435 CUB DR 52 Attachment 2.pdf." The allowances that are in Schedule X of the tariff are slightly lower than the filed amounts due to the lower resulting revenue requirement after processing the case, but the methodology to produce the allowances was the same. The allowances have not been adjusted in subsequent cases.

The methodology used to determine the allowances was to set the construction cost or allowable such that a revenue stream for different terms created an internal rate of return (IRR) set at the Company's cost of capital. The revenue stream assumed billing on a Straight-Fixed-Variable (SFV) rate design that was proposed in the Company's rate case filing. For Category A in the tariff, the revenue stream was assumed for 30 years; for Category B, the revenue stream was assumed for 15 years, and for Category C, the revenue stream was assumed for 5 years. The 30-, 15-, and 5-year terms were used based on an assumption that a customer having gas space heating would remain a customer for 30 years, and so on.

ORDER NO. 12 408

ENTERED OCT 26 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 221

In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.	PRELIMINARY ORDER

DISPOSITION: PARTIAL STIPULATIONS ADOPTED; APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED; FURTHER PROCEEDINGS ORDERED

I. INTRODUCTION

This order addresses Northwest Natural Gas Company's, dba NW Natural request for a general rate revision and approval of a mechanism for recovery of certain environmental remediation costs. We adopt the two partial stipulations filed by the parties, set forth our decision on the remaining disputed issues, and approve a modified mechanism for recovery of certain environmental remediation costs.

This order permanently suspends the tariffs in Advice No. 11-19. NW Natural is directed to file new tariffs consistent with this order to be effective November 1, 2012.

Because of scheduling issues, the complex nature of a number of the disputed issues in this docket, and the need to give NW Natural sufficient time to make its compliance filing, we provide in this order only a brief discussion of the issues and our resolution. An order will be entered shortly describing more fully the parties' positions and the rationale for our decisions.

II. BACKGROUND AND PROCEDURAL HISTORY

NW Natural is a public utility providing natural gas service within the State of Oregon within the meaning of ORS 757.005, and is subject to the Commission's jurisdiction with respect to the prices and terms of service for its Oregon retail customers. NW Natural provides natural gas service to approximately 674,000 retail customers in Oregon.

On December 30, 2011, NW Natural filed Advice 11-19, an application for revised tariff schedules. In its application, the company requested a 6.2 percent increase to its existing revenue requirement.[1] NW Natural states that the primary drivers for its rate request are compliance with safety requirements, enhanced customer service, and company contributions to pension funds. In addition to requesting an increase in its revenue requirement, the company also seeks Commission approval of a mechanism for recovery of various environmental remediation costs.

On January 19, 2012, the Commission suspended NW Natural's proposed tariff revisions for a period of nine months, as authorized by ORS 757.215.[2] On January 23, 2012, a prehearing conference was held and a procedural schedule was established.

During the course of the proceedings, the following were granted leave to intervene as parties: The NW Energy Coalition (NWEC); the Community Action Partnership of Oregon; the Northwest Industrial Gas Users (NWIGU); Northwest Pipeline, GP; and Portland General Electric Company. The Citizens' Utility Board of Oregon (CUB) intervened as a matter of right under ORS 774.180.

The parties conducted discovery, filed several rounds of testimony, and engaged in settlement discussions.

On July 9, 2012, the parties filed an uncontested stipulation addressing a number of issues in this docket. On October 2, 2012, the parties filed a second uncontested stipulation addressing additional issues. A number of disputed issues remained unresolved.

Parties filed prehearing briefs on August 20, 2012. A hearing was held on August 23, 2012. At the time of the hearing, the following issues remained in dispute:

(1) The company's return on equity;
(2) The reasonableness of a hedging transaction related to the company's cost of debt;
(3) The prudence of certain portions of the Mid-Willamette Valley Feeder project;
(4) The appropriate regulatory treatment of certain company contributions to pension funds;
(5) The appropriate regulatory treatment of certain state income taxes; and
(6) The company's proposed mechanism for recovery of certain environmental remediation costs.

Post-hearing briefs were filed on September 12, 2012, and post-hearing reply briefs on September 19, 2012. Oral argument was held on October 11, 2012.

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[1] The company explained that this represents a 4 percent increase in rates when a decoupling deferral of $15.1 million already in customers' current rates is taken into account.
[2] *See* Order No. 12-011.

III. DISCUSSION

We first summarize the Commission's decisions on disputed issues affecting NW Natural's request for a general rate revision and mechanism for recovery of environmental remediation costs. We then provide a brief overview of the two uncontested stipulations filed in this docket, and adopt those stipulations.

A. Disputed Revenue Requirement Issues

1. Return on Equity

NW Natural requests a return on equity (ROE) of 10 percent. NW Natural's cost of capital witness, Dr. Samuel C. Hadaway, presented a range of ROEs from 9.4 to 10.1 percent based on his discounted cash flow analyses. Staff argues that the company's requested 10.0 percent ROE is too high. Staff's own analysis resulted in an ROE range from 8.8 to 9.5 percent. Staff and NWIGU recommend the Commission adopt an ROE of 9.4 percent.

Commission Resolution. Based on the evidence presented, we adopt an ROE of 9.5 percent. This result is within the range of reasonable results presented by both Staff and NW Natural. We find Staff's ROE analysis to be the more credible analysis. We are also persuaded by Staff's criticism of NW Natural's qualitative adjustments and its assessment of NW Natural's relative risk profile.

2. Cost of Debt (Financial Hedge)

In 2007, NW Natural entered into an interest rate swap intended to lock in a target interest rate for an upcoming debt issuance. The financial crisis in 2008 and resulting market effects in 2009 adversely affected the outcome of the swap transaction, ultimately leading the company to suffer a significant loss on the transaction. Staff recommends the company be required to absorb 50 percent of the loss from this hedge on the grounds that it failed to perform a proper risk analysis prior to entering into the transaction. Staff recommends that the Commission implement this recommendation by reducing the cost of a debt issuance and lowering the company's cost of long-term debt.

Commission Resolution. We decline to adopt Staff's recommendation on this issue. We find the company acted consistently with its internal derivatives policy and with a Commission order authorizing it to enter into interest rate swaps. We are not persuaded by Staff that the company acted imprudently or that a disallowance is warranted. NW Natural's cost of debt will be set at 6.056 percent, consistent with the parties' stipulation and unmodified by a hedging disallowance.

3. *Mid-Willamette Valley Feeder Project*

The Mid-Willamette Valley Feeder (MWVF) project consists of four phases of 12-inch diameter transmission lines intended to serve the Albany-Corvallis-Philomath areas. NW Natural seeks to add two phases of this project to the company's rate base in these proceedings: the Perrydale to Monmouth phase and the Monmouth Reinforcement phase. Staff and certain intervenors seek disallowance of the project costs on the grounds that the project was constructed prematurely, and thus imprudently.

Commission Resolution. As we will more fully explain, we conclude that NW Natural has failed to demonstrate that the costs of these projects are prudent.

4. *Pension Costs*

Since 1986, the Commission has allowed regulated utilities to recover in rates its pension expense based on an actuarial calculation of the utility's "Net Periodic Pension Cost," using the standards established by the Federal Accounting Standards Board in its Financial Account Statement (FAS) 87. NW Natural asks the Commission to change its policy to allow it to recover not only its FAS 87 pension expense, but also to determine that its pension contributions made in excess of FAS 87 expense should be included in rate base, and allow the company both recovery of and recovery on the rate-based asset.

Commission Resolution. NW Natural's proposal is denied. As will be discussed more fully, we are not yet convinced that a change to the Commission's existing policy is warranted or that the changed proposed by NW Natural would be the correct policy choice even if a change is warranted. We will open a docket to review the treatment of pension expense on a general, non-utility-specific, basis. NW Natural will continue to recover its existing FAS 87 expense, and as well as use of the balancing account established in docket UM 1475 as it currently exists.

The Commission may conclude during the generic docket that including such assets in rate base is an appropriate policy to apply to all utilities going forward. Should that occur, NW Natural would be able to seek inclusion of an appropriate prepaid pension asset in rate base in future rate proceedings.

5. *State Income Tax*

Oregon state tax rates changed effective with the 2009 tax year. To recognize the tax increase, NW Natural booked for accounting purposes a regulatory asset of $4.48 million —representing the $2.7 million change in its deferred tax balance, plus a gross-up for taxes. In its filing, NW Natural seeks to amortize this $4.48 million amount over a five-year period. Staff and NWIGU-CUB propose removing this amount on the basis that these deferred taxes were booked in prior periods, yet the company sought no deferral order, rendering its request impermissible retroactive ratemaking. They also argue that the request amounts to inappropriate single-issue ratemaking.

Commission Resolution. We deny NW Natural's request for amortization of these deferred tax amounts.[3] Granting such recovery would inappropriately allow special cost recovery of one element of the company's overall taxes.

B. Environmental Remediation Costs

Since 2003, NW Natural has been deferring costs associated with environmental clean-up efforts related to the historic operation of manufactured gas plants. As of September 30, 2011, NW Natural had deferred about $64.5 million in environmental costs, and conservatively estimates its future environmental remediation liability to be an additional $58 million. The company asserts that the deferred costs have been prudently incurred, and asks the Commission to approve a mechanism for these costs through rates, which it refers to as the Site Remediation Recovery Mechanism (SRRM).

Commission Resolution. We approve certain elements of NW Natural's requested SRRM and modify others. We agree with the company that deferral of environmental remediation expenses should continue as they are now, with appropriate offsets when insurance proceeds are recovered.

The majority of Commissioners believe that use of an earnings test (with deadbands) coupled with the Commission's ongoing prudence review will provide an effective incentive for the company to manage its costs. Further, the majority adopts an earnings test but no sharing mechanism. An earnings test may operate as a *de facto* sharing mechanism.[4]

The recovery mechanism will operate, as follows:

- The prudence review for the $64.5 million in environmental costs already deferred shall be conducted in the future. New proceedings will be opened to ensure this review begins promptly.
- Each year, one-fifth of the company's deferred expenses (offset by any proceeds received) will be put into an account for amortization during the November 1 through October 31 period, after the Commission has an opportunity to review those costs and ensure that they were prudently incurred.
- No sharing mechanism will be applied.

[3] Based on the evidence in the record, this adjustment appears to have the effect of reversing NW Natural's proposed $896,000 reduction to miscellaneous revenues.
[4] Commissioner Stephen M. Bloom would require the company to implement a sharing mechanism, and dissents on this point.

- An earnings test with deadbands will be applied. The parties will have the opportunity to address the appropriate deadbands and appropriate application of the earnings test in the new proceedings.
- The following rates of return will be applied to the deferred amounts: Deferred costs that have not been reviewed for prudence will accrue interest at the company's rate of return. Amounts that have been moved into an amortization account each year will accrue interest at the modified blended treasury rate. Amounts that have been reviewed for prudence, but have not yet been moved into an amortization account, will accrue interest at the five-year Treasury rate.

C. Stipulations

The parties to this docket convened settlement conferences on April 4 and 5, 2012.[5] A First Partial Stipulation was filed on July 9, 2012. After additional settlement discussions, a Second Partial Stipulation was filed on October 2, 2012. We describe the stipulations in turn.

1. First Partial Stipulation

The First Partial Stipulation addresses issues related to capital projects, various rate base items, expenses, and revenues.[6]

a. Capital Projects

In the First Partial Stipulation, the stipulating parties agree on a method for ensuring that several projects included in NW Natural's rate base were actually used and useful by the rate effective date; they also stipulate that others should be removed from rate base.[7]

Specifically, NW Natural agrees that the following projects had been cancelled or delayed past the rate effective date and should be removed from rate base: the Corvallis Reinforcement; Westside Transmission Re-rate; Portland System Optimization (Phase 2); Unified Communication Phase 2; Tualatin Bioswale; Sunset Sheds; Coos Bay Retrofit; and Astoria Retrofit.

The company agrees to file attestations confirming the following projects were used and useful by the rate effective date: Monmouth Reinforcement, Perrydale to Monmouth,

[5] NW Natural, Staff, CUB, NWIGU, and NWEC participated in those settlement conferences.

[6] *See* Attachment A to the Partial Stipulation. The parties to the First Partial Stipulation are NW Natural, Staff, CUB, and NWIGU.

[7] The "used and useful" requirement in ORS 757.355(1) states that a public utility may not "directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer."

Tualatin Replacement, Unified Communication Phase 1, Portland System Optimization Phase 1, and 2012 Generators projects. If any of these projects is not in service by the rate effective date, the company agrees to offset its revenue requirement by removing the costs of any such projects from rate base.

The parties also agree to certain treatment of the 2013 Generators and the Nertec Replacement projects. Broadly, the agreement allows NW Natural to recover in rates an amount that reflects the portion of these projects in operation by the rate effective date.

The stipulating parties also agree on a method for ensuring that only the known and measurable costs for the following projects would be included in the company's new rates: Corvallis Reinforcement, Parkrose Retrofit, Portland System Optimization (Phase 1 and Phase 2), Nertec Replacement, Unified Communication Phase 1, and Salem Retrofit.[8]

The stipulation also provides that if the Commission finds that the Monmouth Reinforcement and Perrydale to Monmouth Projects to be prudent, the amount added to rate base for these projects will be the lower of the forecast or actual costs of such projects, incurred as of the rate effective date.[9]

b. Other Adjustments to Revenue Requirement

In addition to agreements on capital costs described above, the stipulating parties agree to a number of additional adjustments to various categories of revenues, expenses, and rate base items. These are set forth in Attachment A to the First Partial Stipulation. The parties explain that all of these adjustments are within the range of outcomes set forth in the parties' testimony in this proceeding.

2. Second Partial Stipulation

The Second Partial Stipulation resolves additional issues, including the company's cost of debt, rate spread and rate design, payroll expenses, working gas inventory, interstate storage sharing, the company's System Integrity Program (SIP), the company's proposal for shorter service window appointments, and the company's proposed changes to service reconnection charges.[10]

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[8] The stipulating parties also agree that NW Natural may file a deferral application in the event the costs exceed the costs anticipated by the company for certain reasons. The parties do not agree to take any particular position on any such deferral application or application for amortization.

[9] As with the previous project, the company reserves the right to file a deferral application if it believes it will incur additional costs related to the projects after the rate effective date, or if the amounts that have been incurred or will be incurred by the rate effective date are greater than the amount included in the company's original filing for that project and are eligible for deferral. The parties do not agree to take any particular position on any such deferral application or application for amortization.

[10] The parties to the Second Partial Stipulation are NW Natural, Staff, CUB, NWIGU, and NWEC.

a. Cost of Long-Term Debt

The stipulating parties agree that the appropriate cost of long-term debt in this docket is 6.056 percent.[11]

b. Rate Spread and Rate Design

1) Residential Rate Design and Related Issues

NW Natural agrees to withdraw the rate design it proposed in this docket. The stipulating parties agree that the existing decoupling mechanism and Weather Adjusted Rate Mechanism (WARM), as currently implemented in accordance with NW Natural's tariffs, should continue. Changes to these mechanisms proposed in the NW Natural's Opening Testimony, and addressed in the Second Partial Stipulation, should be adopted, with the exception of the opt-out provisions in the WARM mechanism, which will remain in effect.

With respect to its residential rate design, NW Natural agrees to continue to employ public purpose charges to fund Energy Trust of Oregon programs. The stipulating parties agree that the monthly customer charge for Schedule 2-Residential Sales Service should be set at $8.00. The stipulating parties also agree that the revisions proposed by the company to Schedule X-Distribution Facilities Extensions for Applicant-Requested Services and Mains, should be adopted, but that the parties will engage in collaborative ongoing discussions regarding the charges for extensions of service to residential customers contained therein. The stipulation also sets forth a process by which Schedule 1-General Sales Service should be eliminated.

Staff agrees to withdraw its request that the company implement seasonal rates, and NW Natural agrees that it will not implement such rates as part of this docket. Finally, the NW Natural agrees to work with parties to make its decoupling-related tariff schedules understandable and clear.

2) Industrial Rate Design

In its original filing, NW Natural proposed changes to its non-residential sales and transportation service schedules, Schedules 31 and 32. The parties to the Second Partial Stipulation agree that the monthly customer charges for these schedules will remain the same as under NW Natural's tariffs that are in effect as of the date of the Second Partial Stipulation.

The stipulating parties agree to eliminate the interruptible service option from Schedule 31 and agree that customers eligible to take service under Schedule 31 will have

[11] As noted previously, this stipulated cost of debt was subject to adjustment if the Commission disallowed a portion of NW Natural's disputed interest rate swap.

a ninety-day period from the rate effective date to opt for interruptible service under that Schedule or the other remaining service option under Schedule 31. Other than certain specified housekeeping changes and the above described opt-in for Schedule 31 customers, all other terms and conditions for service under Schedule 32 will remain as they exist in NW Natural's current tariffs, including the current terms and conditions for interruptible service for Schedule 32.[12]

3) *Long Run Incremental Cost Study and Rate Spread*

With respect to rate spread, the stipulating parties agree to not litigate issues related to NW Natural's proposed Long Run Incremental Cost Study (LRIC) in this docket, except that the parties agree that any rate schedule receiving a zero percent base margin increase under NW Natural's proposed rate spread will instead receive a five percent base margin decrease.[13] Additionally, all parties retain the ability to argue appropriate rate spread allocations based upon LRIC issues for the rate design for any environmental remediation surcharge, if any, that may result from this docket. NW Natural agrees to hold separate workshops on two issues raised by staff in this docket and complete any agreed-upon studies arising out of those workshops before its next general rate case.

c. *Payroll Expenses*

The Second Partial Stipulation resolves three issues relating to payroll expenses: the level of full-time equivalent employees (FTEs), medical benefits, and payroll operations and maintenance (O&M) allocation.

With respect to the level of costs included in the test year related to FTEs, the stipulating parties agree that the regulated company's FTE level should be set at 1,057. This adjustment, on an Oregon allocated basis, reduces the company's proposed payroll level by $3.9 million ($2.7 million in O&M; $1.2 million in capital). To reflect this agreement, the parties agree to apply an adjustment factor to medical benefits for active employees and to workers' compensation costs. This results in an overall adjustment of $752,000. The stipulating parties agree to a test period expense level for medical benefits and workers' compensation of $15.52 million.

Finally, the Second Partial Stipulation resolves disagreements over payroll O&M. The stipulating parties agree that the company's proposed payroll O&M allocation of 69.3 percent should be used to calculate payroll expense.

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[12] The housekeeping changes that the parties have agreed upon are set forth in Sheets 32-1, 32-3, 32-4, and 32-7.32.

[13] The final overall revenue requirement increase, net of offsetting revenues associated with the five percent decreases, will be achieved by uniform percentage increases to the base margin for Schedules 2R Residential Sales, 3C [Commercial] Firm Sales, 31 [Industrial] Firm Sales, and 31C [Commercial] Firm Sales.

d. Working Gas Inventory

Staff and CUB proposed removing the company's working gas inventory from rate base. The parties to the Second Partial Stipulation agree that cushion gas will continue to be included in rate base, but that working gas inventory will be excluded from rate base. The stipulation outlines a method by which the company will request recovery of the carrying costs on working gas inventory and potential recovery of those costs. Under that process, NW Natural may file an application for deferred accounting to allow for the adjustment of future rates to account for the appropriate recovery of working gas inventory and associated carrying costs for the period November 1, 2012 through October 31, 2013, as determined by the Commission.

The parties agree to additional procedural process for this agreement. On May 1, 2013, NW Natural will file testimony supporting its proposed level of working gas to be included in rate base, and its proposed rate of return for working gas. Staff, CUB, and NWIGU, after conducting any necessary discovery, may file testimony supporting alternative levels of working gas to be included in rate base and also alternative rates of return for working gas. Thereafter, the appropriate rate of return ordered by the Commission, with interest, will be implemented through rate adjustment effective November 1, 2013. The prudence of NW Natural's management of storage inventory will continue to be reviewed in NW Natural's annual PGA filing. This process will continue in subsequent PGA years until NW Natural's next general rate case.

e. Interstate Storage Sharing

Staff and CUB proposed altering the existing sharing mechanism for Schedule 185-Special Annual Interstate Storage and Transportation Credit and Schedule 186-Special Annual Core Pipeline Capacity Optimization Credit. The stipulating parties agree that the sharing mechanisms set forth currently in these schedules will remain in place for the time being, but agree to jointly request that a new docket be opened to evaluate these sharing mechanisms, and to request that a decision in the new docket be issued by December 31, 2013.

f. System Integrity Program

NW Natural originally proposed the continuation of its SIP, which provides for certain safety-related capital costs to be tracked into rates annually. It also asked for an increase on the $12 million annual soft cap on the costs that can be tracked into rates through this mechanism. Staff recommended that the Commission discontinue the tracker mechanism associated with the SIP.

Under the Second Partial Stipulation, the company's existing SIP tracker mechanism will remain in effect for two years after the rate effective date. After that, the mechanism will sunset. Prior to this sunset date, NW Natural will make an annual filing specifying projects and expenses to be tracked into rates through the SIP for that year. Parties will have the opportunity to conduct discovery and file responsive testimony. The current soft cap of $12 million will remain in effect, and NW Natural will not recover through the tracking mechanism the first $3.25 million of combined bare steel and leakage capital costs, or any O&M funding embedded in base rates. The parties agree that the Second Partial Stipulation does not affect the "Bare Steel Stipulation" adopted by the Commission in Order No. 01-843, or NW Natural's right to ask the Commission to continue the SIP program past the sunset date.

g. Service Window Appointments

The stipulating parties agree that NW Natural's proposed service window appointment program should be approved, subject to a service window guarantee. The parties agree to review the service window guarantee five years after its implementation date.

h. Service Reconnection Charges

In its original filing, NW Natural proposed increasing its service reconnection charges and changing the framework for its charges from a two-tier structure to a three-tier structure. The stipulating parties agree to a modified three-tier structure.

3. Commission Resolution

The Commission will approve a stipulation if it is an appropriate resolution of the issues and results in just and reasonable rates.[14] When evaluating such rates, the Commission examines "the reasonableness of the overall rates, not the theories or methodologies used or individual decisions made."[15]

Both partial stipulations are adopted. We find the agreements therein constitute reasonable resolutions of the issues addressed, and that they, in combination with our remaining decisions in this order, will result in just and reasonable rates.

IV. ORDER

IT IS ORDERED that:

1. The First Partial Stipulation and Second Partial Stipulation, attached as Appendices A and B, are adopted.

[14] *See, In re PacifiCorp 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 at 6 (Oct 30, 2009); *In re PacifiCorp Request for a Gen. Rate Revision*, Docket No. UE 210, Order No. 10-022 at 6 (Jan 26, 2010).

[15] *In re Application of Portland Gen. Elec. Co. for an Investigation into Least Cost Plant Retirement*, Docket No. DR 10, *et al.*, Order No. 08-487 at 7-8 (Sept 30, 2008).

2. Advice No. 11-19 is permanently suspended.

3. Northwest Natural Gas Company, dba NW Natural, will file new tariffs consistent with this order to be effective November 1, 2012.

4. Consistent with this order, additional proceedings will be opened to address issues related to environmental remediation costs and pension costs.

Made, entered, and effective OCT 26 2012.

Susan K Ackerman /mo
Susan K. Ackerman
Chair

John Savage /mD
John Savage
Commissioner

<u>Commissioner Bloom concurring in part and dissenting in part:</u>

With the exception of the majority's decision on the sharing mechanism for environmental remediation costs, I concur.

SBloom
Stephen M. Bloom
Commissioner

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 221

In the Matter of NORTHWEST NATURAL GAS COMPANY Application for a General Rate Revision.	**PARTIAL STIPULATION**

This Partial Stipulation is entered into for the purpose of resolving specific issues among all parties to UG 221, Northwest Natural Gas Company's ("NW Natural" or "the Company") 2011 general rate case.

PARTIES

1. The parties to this Partial Stipulation are NW Natural, Commission Staff ("Staff"), the Citizens' Utility Board of Oregon (CUB), and the Northwest Industrial Gas Users (NWIGU) (collectively, "Parties"). Northwest Energy Coalition (NWEC) participated in settlement discussions, is not a party to this stipulation, but does not oppose the stipulation. Community Action Partnership of Oregon, Northwest Pipeline GP, and Portland General Electric Company are parties to this case but did not participate in settlement discussions.

BACKGROUND

2. On December 30, 2011, NW Natural filed revised tariff sheets to be effective February 1, 2012, seeking a general rate increase of approximately $43.7 million, or 6.2 percent. In its filing, NW Natural used an historic base period of the 12 months ended December 31, 2011, with adjustments to calculate a future test period of the 12 months ending October 31, 2013 ("Test Year").

3. In Order No. 12-011, issued on January 19, 2012, the Public Utility Commission of Oregon ("Commission") suspended the Company's application for a general rate revision

for a period of nine months. Based on the suspension, the effective date of the revised tariff sheets will be November 1, 2012.

4. Pursuant to Administrative Law Judge Hardie's Prehearing Conference Memorandum of January 23, 2012, the parties to this docket convened settlement conferences on April 4 and 5, 2012. NW Natural, Staff, CUB, NWIGU, and NWEC participated in those settlement conferences.

5. On May 3, 2012, Staff, CUB, NWIGU, and NWEC filed Opening Testimony responding to the Company's Initial Filing.

6. The Parties again convened settlement conferences on May 22 and 23, 2012.

7. As a result of those settlement conferences, the Parties have reached a settlement resolving some of the issues in this case. This Partial Stipulation reduces NW Natural's proposed rate increase and resolves certain issues raised by Staff, CUB, and NWIGU. The final amount of NW Natural's rate increase, if any, will be determined following Commission resolution of the issues unresolved by this Partial Stipulation.

AGREEMENT

The Parties agree to settle the issues in this Partial Stipulation consistent with the numbers provided in Attachment A. Specifically, the issues settled in this Partial Stipulation are:

Capital Projects

8. In their testimony, Staff, CUB, and NWIGU raised concerns as to whether certain construction projects included in Test Year rate base, but not completed as of the date the rate case was filed, would be used and useful by the rate effective date or in the Test Year. Specifically, in Opening Testimony, these parties questioned whether the following capital projects would be used and useful: Corvallis Reinforcement; Nertec meters; Perrydale to Monmouth; Tualatin Replacement training facility and land; Unified Communication (Phase 1 and Phase 2); Westside Transmission Re-rate; Portland System Optimization (Phase 1 and

Phase 2); Tualatin Bioswale; Sunset Sheds; Generators 2012 and 2013; Coos Bay Retrofit; and Astoria Retrofit.

9. In addition, Staff, CUB, and NWIGU raised concerns regarding the prudence of the Monmouth Reinforcement ($8,087,000) and Perrydale to Monmouth ($18,131,000) projects. Finally, CUB and NWIGU questioned whether the costs associated with the Corvallis Reinforcement, Parkrose Retrofit, Portland System Optimization (Phase 1 and Phase 2), Nertec Replacement, Unified Communication Phase 1 and Salem Retrofit were known and measurable.

10. The Company has confirmed that the following projects have been cancelled or delayed past the rate effective date: Corvallis Reinforcement; Westside Transmission Re-rate; Portland System Optimization (Phase 2); Unified Communication Phase 2; Tualatin Bioswale; Sunset Sheds; Coos Bay Retrofit; and Astoria Retrofit. NW Natural agrees to remove the amounts that were included in rate base for these projects in the Test Year, consistent with Attachment A.

11. Further, the Company clarified that the Monmouth Reinforcement, Perrydale to Monmouth, Tualatin Replacement, Unified Communication Phase 1, Portland System Optimization Phase 1, and 2012 Generators projects will all be used and useful by the rate effective date. To remove any continuing concerns, however, the Company agrees that by October 1, 2012 it will file an attestation from senior management confirming that these projects either are or will be used and useful by the rate effective date. The attestation filing will also confirm the amount that the Company has invested in each of those projects as of the date of the filing, and, if the project is not yet complete, the Company's reasonable expectation of costs that will be incurred up to the rate effective date.

12. Except as discussed in paragraph 13 below, if the attestation described in paragraph 11 demonstrates that a project is, or will be, used and useful by the rate effective date, the Parties agree that the lower of the forecast or the actual amount expended on that

project as of the rate effective date may be added to rate base and recovered through the revenue requirement. Nothing in this paragraph precludes the Company from filing a deferral application in the event that the Company believes it will incur additional costs related to the project after the rate effective date, or if the amounts that have been incurred or will be incurred by the rate effective date are greater than the amount included in the Company's original filing for that project and are eligible for deferral. And, nothing precludes other Parties from taking any position (supporting or opposing) on the deferral application and application for amortization.

13. If the Company's attestation demonstrates that the Monmouth Reinforcement and the Perrydale to Monmouth projects will be used and useful by the rate effective date, there remains an issue of whether or not these two projects were prudent. The Parties may argue that these projects either were or were not prudent in this proceeding. To the extent the Commission finds that such projects were prudent, the lower of the forecast or actual costs of such projects, incurred as of the rate effective date, will be added to rate base for purposes of the Company's revenue requirement. Nothing in this paragraph precludes the Company from filing a deferral application in the event that the Company believes it will incur additional costs related to a project after the rate effective date, or if the amounts that have been incurred or will be incurred by the rate effective date are greater than the amount included in the Company's original filing for that project and are eligible for deferral. And, nothing precludes other Parties from taking any position (supporting or opposing) on the deferral application and application for amortization.

14. In the case of the Nertec project, the Parties understand that it is possible that not all of the Nertec meters will be installed by the rate effective date. For the purposes of this settlement, the Parties agree that, provided that the Company attests that all of the Nertec meters will be received by the rate effective date and installed by the end of the Test Period, 50% (fifty percent) of the Test Year costs of the meters will be added to rate base.

15. In regards to the Salem Retrofit, to remove any continuing concerns, the Company agrees that by October 1, 2012 it will file an attestation confirming that the project either is or will be used and useful by the rate effective date. The filing will also confirm the amount that the Company has invested in the project as of the date of the filing, and, if the project is not yet complete, the Company's reasonable expectation of costs that will be incurred up to the rate effective date.

16. The Parties agree that the lower of the forecast or actual costs of the project, incurred as of the rate effective date, will be added to rate base for purposes of the Company's revenue requirement. Nothing in this paragraph precludes the Company from filing a deferral application in the event that the Company believes it will incur additional costs related to the project after the rate effective date, or if the amount that has been incurred or will be incurred by the rate effective date is greater than the amount included in the Company's original filing for that project and are eligible for deferral. And, nothing precludes other Parties from taking any position (supporting or opposing) on the deferral application and application for amortization.

17. The Company also agrees to remove the following projects, which are scheduled to be completed during the Test Year but after the rate effective date: Portland System Optimization Phase 2; and Unified Communications Phase 2. The Parties agree that the 2013 Generators will be averaged into rate base such that 50% of the associated costs are reflected in rate base in the Test Year.

18. In the event that the Company's attestation demonstrates that one or more projects described above will not be used and useful by the rate effective date, the revenue requirement in the case will be offset by the effect of removing the costs of such project or projects from rate base.

19. Regarding those projects that will not be used and useful in time to be included in rates by the rate effective date, the Parties are aware that the Company may ask the

Commission to consider including those costs in rates through a tracker or at the time of a Purchased Gas Adjustment, but the impartation of this knowledge is not intended in any way to limit the Parties participation in future dockets or to prejudge the Parties' positions on such requests.

Revenue Adjustment related to the Company's Proposed Rate Design

20. In its Opening Testimony, Staff argued that the Company had understated its projected revenues for the Test Year by overstating the amount it would lose through customer attrition in the event that its rate design proposal is adopted (the "Company's Proposed Revenue Adjustment"). As a result, in its Opening Testimony, Staff recommended that the Company's Proposed Revenue Adjustment should be removed, and estimated a downward adjustment of $5.356 million. After discussion, Staff agreed that the Company's Proposed Revenue Adjustment should be $2.3 million, and the Parties agree that an adjustment of $2.3 million of revenues should be made in the event that the Commission adopts the Company's proposed rate design (as proposed in the Company's Initial Filing). The parties agree that if the Commission does not adopt the Company's proposed rate design, then the Company should increase expected revenues by $2.3 million.

Parkrose Retrofit

21. In its Opening Testimony, Staff recommended that the Company's proposed recovery for the Parkrose Retrofit be reduced by $0.621 million. The Parties agree that Staff will withdraw this recommendation, and that the Company should recover its costs related to the Parkrose Retrofit as proposed.

Rate Case Amortization

22. In its Opening Testimony, CUB/NWIGU recommended that the Company's Rate Case Expense be amortized over five instead of the three years assumed in the Company's proposal, resulting in a downward adjustment to Operating and Maintenance Expense (O&M)

of $0.093 million. The Parties agree that CUB/NWIGU will withdraw this recommendation and that the Company should recover its Rate Case Expense as proposed.

Uncollectibles Adjustment

23. In its Opening Testimony, CUB/NWIGU recommended that the Company's proposal for recovery of uncollectible expense be reduced by $0.448 million. The Parties agree that CUB/NWIGU will withdraw this recommendation, and that the Company should recover its uncollectibles as proposed.

Injuries and Damages Expense

24. In its Opening Testimony, CUB/NWIGU recommended that the Company's proposed recovery for Injuries and Damages Expense be reduced by $0.126 million. The Parties agree that CUB/NWIGU will withdraw that recommendation and that the Company should recover its Injuries and Damages Expense as proposed.

Directors and Officers Insurance

25. In Opening Testimony, Staff recommended that NW Natural be allowed to recover only 50% of the costs of Directors and Officers Insurance above the first layer of coverage. CUB/NWIGU made a different but similar recommendation. The Parties agree that the Company's O&M expense should be adjusted by a reduction of $0.272 million to remove that portion of the costs of D&O insurance consistent with Staff's recommendation.

Incentive Pay

26. In its Opening Testimony, Staff and CUB/NWIGU both recommended that the Commission make a downward adjustment to the Company's proposal for recovery of incentive pay. The Parties agree the Company's proposed recovery for incentive pay should be adjusted by an amount that represents a 25% reduction to Staff's original recommendation. This amount will vary from the adjustment proposed in Staff's testimony to the extent required to match the Commission's ultimate determination on full-time employees (FTEs), such that the adjustment will represent the application of the Commission precedent described in Staff's

testimony to the number of FTEs determined by the Commission to be includable in revenue requirement, and then reduced by 25%.

Administrative and General

27. In its Opening Testimony, Staff recommended that the Company's proposed Administrative and General (A&G) expense should be reduced by $1.982 million, and CUB/NWIGU has specifically proposed that the Company's proposed recovery for American Gas Association dues (which is included in A&G expense) should be reduced by $148,114. After discussions the Parties agreed that the Company's A&G expense should be adjusted by ($1.212 million).

Miscellaneous Revenue

28. In its Opening Testimony, and later corrected through an errata filing, Staff recommended that the Company's Miscellaneous Revenue proposal be adjusted by $0.658 million. After discussion, the Parties agreed that the Commission should adopt an adjustment of $0.494 million, which represents a reduction of 25% of Staff's adjustment proposed in its corrected Opening Testimony.

Advertising

29. In its Opening Testimony, Staff recommended that the Company's advertising expense for Category A advertising expenditures be reduced by $0.930 million to match the level presumed prudent under OAR 860-026-0022(3)(a). The Parties agree that the Company should be allowed to recover Category A expense commensurate with the per-customer level of $2.19 allowed in the Company's last rate case and applied to Test Year customer levels. Additionally, the Parties agree that NW Natural should recover $510,000 of costs for Category B expenses.

Research and Development

30. In its Opening Testimony, Staff recommended that the Company's proposal for Research and Development expense be reduced by $0.006 million. The Parties agree that

the Commission should accept this adjustment, and that the Company should be allowed to collect $0.743 million of expenses related to Research and Development.

Materials and Supplies

31. In its Opening Testimony, CUB/NWIGU recommended that the Company's proposal for Materials and Supplies included in rate base should be reduced by $0.633 million. The Parties agree that this recommendation should be accepted.

Contributions in Aid of Construction (CIAC)

32. In its Opening Testimony, CUB/NWIGU recommended that the Company's rate base be reduced by $0.069 million to account for its adjustment related to CIAC. The Parties agree that the Company's rate base should be adjusted by this recommendation.

Customer Deposits

33. In its Opening Testimony, CUB/NWIGU recommended that the Company's rate base be reduced by $5.1 million to account for the Company's possession of customer deposits. All Parties, including the Company agree to accept this recommendation. In addition, as an offset to this reduction, the Company's O&M expense should be increased by $.005 for interest expense on the customer deposits.

Injuries and Damages Reserves

34. The Parties agree that the Company's proposed rate base should be reduced by $0.211 million in recognition of the CUB/NWIGU recommendation on this issue.

35. This Partial Stipulation will be offered into the record as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Partial Stipulation at hearing, if needed, and recommend that the Commission issue an order adopting the Partial Stipulation.

36. If this Partial Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Partial Stipulation. The Parties reserve the right to cross-examine witnesses and put in such

evidence as they deem appropriate to respond fully to such issues presented including the right to raise issues that are incorporated in the settlements embodied in this Partial Stipulation.

37. The Parties have negotiated this Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Partial Stipulation or imposes additional material conditions in approving this Partial Stipulation, any Party shall have the right to withdraw from the Partial Stipulation, along with any other rights provided in OAR 860-001-0350(9), including the right to present evidence and argument on the record in support of the Partial Stipulation, and shall be entitled to seek reconsideration pursuant to OAR 860-001-0720.

38. By entering into this Partial Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Partial Stipulation, other than as specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Partial Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Partial Stipulation.

39. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Partial Stipulation is entered into by each Party on the date entered below such Party's signature.

SIGNATURE PAGE TO FOLLOW

ORDER NO. 12 408

NW NATURAL

By: Lisa Rackner

Printed Name: Lisa Rackner

Date: 7-9-12

STAFF

By: __________

Printed Name: __________

Date: __________

CUB

By: __________

Printed Name: __________

Date: __________

NWIGU

By: __________

Printed Name: __________

Date: __________

ORDER NO. 12 408

NW NATURAL

By: ____________________

Printed Name: ____________________

Date: ____________________

STAFF

By: ____________________

Printed Name: Jason Jones

Date: 7/6/12

CUB

By: ____________________

Printed Name: ____________________

Date: ____________________

NWIGU

By: ____________________

Printed Name: ____________________

Date: ____________________

ORDER NO. 12 408

NW NATURAL	STAFF
By:	By:
Printed Name:	Printed Name:
Date:	Date:

CUB	NWIGU
By:	By:
Printed Name: G. Catriona McCracken	Printed Name:
Date: 7-6-2012	Date:

ORDER NO. 12 408

NW NATURAL	STAFF
By: ______________	By: ______________
Printed Name: ______________	Printed Name: ______________
Date: ______________	Date: ______________
CUB	NWIGU
By: ______________	By: Paula E. Pyron
Printed Name: ______________	Printed Name: Paula E. Pyron
Date: ______________	Date: 7/6/12

UG 221 Northwest Natural
First Stipulation
Dollars (000s)

ATTACHMENT A

		Staff & Intervenors Adjustments Oregon Allocation
S-2	Corvallis Reinforcement	(8,370)
S-4	Nertec Replacement	(844)
S-5	Parkrose Retrofit	0
S-7	Tualatin replacement, training facility & land	0
S-8	Unified Communication Phase 1 (PBX Switch)	0
S-9	Westside Transmission Rerate	(1,800)
S-10	Directors and Officers Insurance	(272)
S-11	Incentive Compensation	(2,573)
S-13	Various Customer Service, G&A Expenses	(1,212)
S-15	Research & Development	(6)
S-19	Advertising	(382)
S-21	Miscellaneous Revenue	494
C-1	Portland Optimization Phase II	(563)
C-2	United Communication Phase II	(450)
C-3	Tualatin Bio Swale	(540)
C-4	Sunset Sheds	(603)
C-5	Coos Bay Retrofit	(625)
C-6	Astoria Retrofit	(400)
C-7	Materials and Supplies (M&S)	(633)
C-8	Contributions in Aid of Construction (CIAC)	(69)
C-9	Customer Deposits	(5,101)
C-9	Customer Deposits - Interest Expense	5
C-10	Injuries & Damages Reserves	(211)
C-11	Portland System Optimization Phase I	0
C-12	2012 Generator	0
C-13	Salem Retrofit	0
C-14	2013 Generators	0

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 221

In the Matter of NORTHWEST NATURAL GAS COMPANY Application for a General Rate Revision.	**SECOND PARTIAL STIPULATION**

This Second Partial Stipulation is entered into for the purpose of resolving specific issues among certain parties to UG 221, Northwest Natural Gas Company's ("NW Natural" or "the Company") 2011 general rate case ("Second Partial Stipulation").

PARTIES

1. The parties to this Second Partial Stipulation are NW Natural, Commission Staff ("Staff"), the Citizens' Utility Board of Oregon (CUB), the Northwest Industrial Gas Users (NWIGU), and Northwest Energy Coalition (NWEC) (collectively, "Parties"). Community Action Partnership of Oregon, Northwest Pipeline GP, and Portland General Electric Company are parties to this case but did not participate in settlement discussions.

BACKGROUND

2. On December 30, 2011, NW Natural filed revised tariff sheets to be effective February 1, 2012, seeking a general rate increase of approximately $43.7 million, or 6.2 percent. In its filing, NW Natural used an historic base period of the 12 months ended December 31, 2011, with adjustments to calculate a future test period of the 12 months ending October 31, 2013 ("Test Year").

3. In Order No. 12-011, issued on January 19, 2012, the Public Utility Commission of Oregon ("Commission") suspended the Company's application for a general rate revision for a period of nine months. Based on the suspension, the effective date of the revised tariff sheets will be November 1, 2012.

4. Pursuant to Administrative Law Judge (ALJ) Hardie's Prehearing Conference Memorandum of January 23, 2012, the parties to this docket convened settlement conferences on April 4 and 5, 2012. The Parties participated in those settlement conferences.

5. On May 3, 2012, Staff, CUB, NWIGU, and NWEC filed Opening Testimony responding to the Company's Initial Filing.

6. The Parties again convened settlement conferences on May 22 and 23, 2012.

7. On June 15, 2012, NW Natural filed Reply Testimony.

8. As a result of the May 2012 settlement conferences, NW Natural, Staff, CUB, and NWIGU reached a settlement resolving some of the issues in this case and filed a Partial Stipulation on July 9, 2012.

9. On July 20, 2012, Staff, CUB, NWIGU, and NWEC filed Rebuttal Testimony.

10. The Parties continued settlement discussions in the first half of August.

11. The ongoing August 2012 settlement discussions among the Parties resulted in the resolution of additional issues.

12. On August 9, 2012, NW Natural filed Surrebuttal Testimony.

13. On August 14, 2012, Staff filed a letter with ALJ Hardie indicating that the Parties had reached a settlement in principle on certain additional issues in this proceeding. This Second Partial Stipulation memorializes the Parties' agreement on these additional issues.

AGREEMENT

Cost of Long-Term Debt

14. The Parties have resolved all issues related to the cost of long-term debt, with the exception of Staff's proposed adjustment relating to the Company's interest rate hedge loss. The Parties agree that the appropriate cost of long-term debt is 6.056 percent; however, should the Commission adopt an adjustment related to the interest rate hedge loss, the 6.056 percent will be reduced consistent with the Commission's decision.

Residential Rate Design and Related Issues

15. NW Natural agrees to withdraw its proposed rate design that was set forth in the testimony of Russell Feingold. The Parties agree that the existing decoupling mechanism and Weather Adjusted Rate Mechanism (WARM), as currently implemented in accordance with NW Natural's tariffs, should continue and that the changes to these mechanisms proposed in the Company's Opening Testimony should be adopted, with the exception of the opt-out provisions in the WARM mechanism, which provisions will remain in effect. Changes related to the mechanisms will specifically include:

a. Both the WARM and decoupling mechanism will incorporate certain updates developed in preparing this case. In particular, the mechanisms will incorporate updated values of normalized use per customer, updated normal heating degree days (HDDs) by zone and the results of using updated statistical coefficients relating HDDs to therm usage.

b. Customer counts and updated normalized use-per-customer values in the decoupling mechanism will reflect the withdrawal of NW Natural's proposed rate design.

c. The elasticity component of the decoupling mechanism will be removed.

d. The decoupling deferral period will be changed to November - October to coincide with the PGA tracker year.

e. In the decoupling mechanism, usage for the month of May will be normalized in the same manner as November usage, where usage is normalized by the actual WARM effect attributable to the month that is included in customer bills.

16. NW Natural will continue to employ public purpose charges to fund Energy Trust of Oregon programs.

17. The Parties agree that the customer charge for Schedule 2–Residential Sales Service should be set at $8.00.

18. The Parties agree that Schedule 1–General Sales Service should be eliminated. Schedule 1R customers will be migrated into Schedule 2R and Schedule 1C customers will be migrated into Schedule 3C. Because customers currently subject to Schedule 1 are not part of the WARM program, NW Natural will not automatically include such customers in WARM when transferring them to Schedule 2, and will instead allow such customers to opt to participate in the WARM program at their election.

19. The Parties agree that the revisions to Schedule X– Distribution Facilities Extensions for Applicant-Requested Services and Mains proposed by the Company should be adopted. The Parties agree to engage in collaborative discussions regarding the appropriate design of charges for extensions of service to residential customers.

20. Staff agrees to withdraw its request that the Company implement seasonal rates, and the Company agrees that it will not implement such rates as part of this case.

21. The Company agrees to work with parties to make its decoupling-related tariff schedules understandable and clear.

Industrial Rate Design

22. The Company proposed changes to its non-residential sales and transportation service schedules, Schedule 31 and Schedule 32. The Parties agree that the customer charges for these schedules will remain the same as under NW Natural's tariffs that are in effect as of the date of the execution of this Second Partial Stipulation.

23. The Parties agree to eliminate the interruptible service option from Schedule 31 and agree that customers eligible to take service under Schedule 31 will have a ninety-day period from the rate effective date to opt for interruptible service under Schedule 32 or the other remaining service options under Schedule 31. Certain housekeeping changes were proposed by the Company to Schedule 32 and have been agreed to by the Parties as shown on Sheets 32-1, 32-3, 32-4 and 32-7 in the attached Exhibit A to this Second Partial Stipulation. Other than allowing for elections of service by customers eligible for Schedule 31, and the

housekeeping changes described in this paragraph 23, the terms of service and interruptible service options for Schedule 32 customers will remain unchanged from the tariffs in effect as of the date of execution of this Second Partial Stipulation.

Level of Full-Time Equivalent Employees

24. In Rebuttal Testimony, Staff proposed that the Company's revenue requirement be calculated based on 1,020 regulated Company full-time equivalent employees (FTEs) and NWIGU-CUB proposed 1,072 total Company FTEs. The Company proposed 1,095 regulated Company FTEs in Surrebuttal Testimony. The Parties agree that the regulated Company FTE level should be set at 1,057. This adjustment, on an Oregon allocated basis, reduces the Company's proposed payroll level included in its original application in this proceeding by $3.9 million, of which $2.7 million is operations and maintenance (O&M) and $1.2 million is capital.

Medical Benefits

25. The Parties agree that the test period expense amount of $16.27 million proposed to be included in rates by NW Natural, which is the total company expense amount allocated to Oregon and reduced by 1.78 percent for unregulated FTE not included in the revenue requirement, should be reduced to reflect the agreed-upon FTE level. The Parties agree that this test period expense level should be adjusted downward by the ratio of the number of stipulated FTEs to the number of FTEs used by the Company to calculate its requested rate increase. The appropriate FTE ratio is 1,057 FTEs to 1,111 FTEs, which results in an adjustment factor of 95.14 percent. It is not appropriate to apply this adjustment factor to medical benefits for retirees. Applying this adjustment factor to medical benefits for active employees and to workers compensation results in an overall adjustment of $752 thousand. Parties agree to a test period expense level for medical benefits and workers' compensation of $15.52 million. This is comprised of $13.51 million for medical benefits for active employees, $808 thousand for medical benefits for retirees, and $1.2 million for workers' compensation.

The split between O&M and capital related to this adjustment will be 70% to O&M and 30% to capital, with the related change in depreciation expense constituting 2.7% of the capital change.

Payroll O&M Allocation

26. NWIGU-CUB proposed reducing the Company's proposed payroll O&M allocation from 69.3 percent to 63.7 percent. The Parties agree that NWIGU-CUB will withdraw this recommendation and that the Company's payroll O&M allocation of 69.3 percent should be used to calculate payroll expense.

Working Gas Inventory

27. Staff and CUB proposed removing working gas inventory from rate base. The Parties agree that cushion gas will continue to be included in rate base, but that working gas inventory will be excluded from rate base and that the Company' will request recovery of the carrying costs on working gas inventory through the following process:

a. On or before November 1, 2012, NW Natural will file a deferred accounting application to allow for the adjustment of future rates to account for the appropriate recovery of working gas inventory and associated carrying costs for the period November 1, 2012 through October 31, 2013, as will be determined by the Commission through the process outlined below. The Parties agree to support the Company's application for deferred accounting.

b. On May 1, 2013, NW Natural will file testimony with the Commission supporting: (a) its proposed level of working gas to be included in rate base for the period November 1, 2012 through October 31, 2013, and (b) its proposed rate of return for working gas. Staff, CUB, and NWIGU, after conducting any necessary discovery, may file reply testimony supporting alternative levels of working gas to be included in rate base and alternative rates of return for working gas.

c. The ratemaking treatment for working gas inventory approved by the Commission for the period November 1, 2012 through October 31, 2013, including the appropriate rate of return ordered by the Commission, with interest, will be implemented through rate adjustment effective November 1, 2013.

d. The prudence of NW Natural's management of storage inventory will continue to be reviewed in NW Natural's annual PGA filing.

28. The process for evaluating working gas inventory described above will continue in subsequent PGA years until NW Natural's next general rate case

Interstate Storage Sharing

29. Staff and CUB proposed altering the existing sharing mechanism for Schedule 185–Special Annual Interstate Storage and Transportation Credit and Schedule 186–Special Annual Core Pipeline Capacity Optimization Credit. The Parties agree that the sharing mechanisms set forth currently in these schedules will remain in place for the time being. However, the Parties will jointly request that a new contested case docket be opened to evaluate these sharing mechanisms. The Parties agree that they will request that the Commission decision in this new docket be issued on or before December 31, 2013. All Parties reserve the right to take any position in the new proceeding.

System Integrity Program

30. In its Direct Testimony, NW Natural proposed the continuation of its System Integrity Program (SIP), which provides for certain capital costs to be tracked into rates annually. The Company also recommended that the soft cap placed on the costs that can be tracked into rates through this mechanism be increased from $12 million annually to $26.3 million for 2013 to account for a bare steel replacement project planned for that year. In its Opening and Rebuttal Testimony, Staff recommended that the Commission discontinue the tracker mechanism associated with NW Natural's SIP.

31. The Parties agree that the Company's existing tracker mechanism associated with SIP will remain in effect for two years after the rate effective date in this case, after which date it will sunset. NW Natural agrees that prior to this sunset date, NW Natural will make a

filing each year specifying projects and expenses that are proposed to be tracked into rates through the SIP for that year. Parties will have the opportunity to conduct discovery and file responsive testimony. NW Natural agrees that the soft cap of $12 million described in the stipulation adopted in Order No. 09-067 will remain in effect, and that it will not recover through the tracking mechanism the first $3.25 million of combined bare steel and leakage capital costs, or any of its O&M funding embedded in base rates. Nothing in this agreement should be construed as affecting the Bare Steel Stipulation adopted in Order No. 01-843, which remains in effect until 2021 or until completion of the bare steel removal. Nothing in this agreement affects NW Natural's right to request that the Commission continue the SIP program past the date of the sunset.

Long Run Incremental Cost Study and Rate Spread

32. The parties agree to not litigate issues related to NW Natural's proposed Long Run Incremental Cost Study (LRIC) in this docket, except that the parties agree that any rate schedule receiving a zero percent base margin increase under the proposed rate spread in NW Natural's Direct Testimony will instead receive a five percent base margin decrease. A spreadsheet showing this agreement is attached as Exhibit B. The final overall revenue requirement increase, net of offsetting revenues associated with the aforementioned five percent decreases, will be achieved by uniform percentage increases to the base margin for Schedules 2R Residential Sales, 3C [Commercial] Firm Sales, 3I [Industrial] Firm Sales, and 31C [Commercial] Firm Sales.[1] Additionally, all Parties retain the ability to argue appropriate rate spread allocations based upon relative LRIC issues for the rate design appropriate for any environmental remediation surcharge, if any, that may result from this case. The Company agrees to hold workshops on each of (1) revenue requirement functionalization and (2) the

[1] The intent of the parties is that any decreases to base margin in one schedule will be made up for with offsetting increases to the base margin for other schedules, such that there is no impact to revenue requirement from the rate design agreed to.

attributable lengths of distribution mains and related cost impacts by customer class of mains in the near future to determine the nature and scope of any appropriate studies to be completed. The Company agrees to complete any agreed-upon studies prior to filing its next Oregon general rate case.

Service Window Appointments

33. The Parties agree that the Company's proposed service window appointment program should be approved, subject to the service window guarantee described in this paragraph. Beginning on May 1, 2013, a service window guarantee of $50 will be charged to the Company for each missed service window appointment if the Company meets fewer than 90 percent of scheduled service window appointments. These $50 charges will be tracked through the PGA year and returned to customers as a whole as a credit coincident with the annual PGA.

34. The Parties agree to clarify the tracking and accounting for missed appointments for purposes of determining customer credits related to the service window guarantee.

35. The Parties agree to review the service window guarantee after five years from the implementation date of the service window guarantee to determine if it continues to be necessary.

Service Reconnection Charges

36. The Company proposed increasing its service reconnection charges and changing the framework from a two-tier structure to a three-tier structure, resulting in the following proposal: Tier 1—During business hours, $40; Tier 2—After-hours scheduled for the next business day, $80; Tier 3—Same-day or reconnections on Saturdays, Sundays, or holidays, $185. Staff and CUB objected to the Company's proposed changes. The Parties agree that for purposes of settlement in this case the following three-tier structure should be adopted:

a. Tier 1—During business hours, $30;

b. Tier 2—After-hours scheduled for the next business day, $80;

c. Tier 3—Same-day or reconnections on Saturdays, Sundays, or holidays, $100.

Customer Deposits

37. In the Partial Stipulation (filed on July 9, 2012), Paragraph 33 related to customer deposits stated that "the Company's O&M expense should be increased by $.005 for interest expense on the customer deposits." The Parties agree that the amount in this sentence should be corrected to be read "$.005 million" rather than "$.005."

Filing of Stipulation

38. This Second Partial Stipulation will be offered into the record as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Second Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Second Partial Stipulation at hearing, if needed, and recommend that the Commission issue an order adopting the Second Partial Stipulation.

39. If this Second Partial Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Second Partial Stipulation. The Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to such issues presented including the right to raise issues that are incorporated in the settlements embodied in this Second Partial Stipulation.

40. The Parties have negotiated this Second Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Second Partial Stipulation or imposes additional material conditions in approving this Second Partial Stipulation, any Party shall have the right to withdraw from the Second Partial Stipulation, along with any other rights provided in OAR 860-001-0350(9), including the right to present evidence and argument on the record in support of the Second Partial Stipulation, and shall be entitled to seek reconsideration pursuant to OAR 860-001-0720.

41. By entering into this Second Partial Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Second Partial Stipulation, other than as specifically identified in the body of this Second Partial Stipulation. No Party shall be deemed to have agreed that any provision of this Second Partial Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Second Partial Stipulation.

42. This Second Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Second Partial Stipulation is entered into by each Party on the date entered below such Party's signature.

SIGNATURE PAGE TO FOLLOW

ORDER NO. 12 408

NW NATURAL

By: C. A. Mi

Printed Name: C. Alex Miller

Date: 9/28/12

STAFF

By: ______________________

Printed Name: ______________________

Date: ______________________

CUB

By: ______________________

Printed Name: ______________________

Date: ______________________

NWIGU

By: ______________________

Printed Name: ______________________

Date: ______________________

NWEC

By: ______________________

Printed Name: ______________________

Date: ______________________

NW NATURAL

By: ____________________

Printed Name: ____________________

Date: ____________________

STAFF

By: ____________________

Printed Name: Jason Jones

Date: 9/28/12

CUB

By: ____________________

Printed Name: ____________________

Date: ____________________

NWIGU

By: ____________________

Printed Name: ____________________

Date: ____________________

NWEC

By: ____________________

Printed Name: ____________________

Date: ____________________

NW NATURAL

By: ______________________

Printed Name: ______________________

Date: ______________________

STAFF

By: ______________________

Printed Name: ______________________

Date: ______________________

CUB

By: G.C.M.

Printed Name: G. Catriona McCracken

Date: 9-28-12

NWIGU

By: ______________________

Printed Name: ______________________

Date: ______________________

NWEC

By: ______________________

Printed Name: ______________________

Date: ______________________

NW NATURAL

By: ______________________

Printed Name: ______________________

Date: ______________________

STAFF

By: ______________________

Printed Name: ______________________

Date: ______________________

CUB

By: ______________________

Printed Name: ______________________

Date: ______________________

NWIGU

By: ______________________

Printed Name: Chad Stokes

Date: 9-28-12

NWEC

By: ______________________

Printed Name: ______________________

Date: ______________________

NW NATURAL

By: ______________________

Printed Name: ______________________

Date: ______________________

STAFF

By: ______________________

Printed Name: ______________________

Date: ______________________

CUB

By: ______________________

Printed Name: ______________________

Date: ______________________

NWIGU

By: ______________________

Printed Name: ______________________

Date: ______________________

NWEC

By: Wendy G

Printed Name: Wendy Gerlitz

Date: October 1, 2012

UG 221

Second Partial Stipulation

Exhibit A

Schedule 32 Changes

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 Original Sheet 32-1

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE

SERVICE AVAILABILITY:

Service under this Rate Schedule is available on the Company's Distribution System to Non-Residential Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part, provided that the Company determines, in its sole judgment, that adequate supply and capacity exists to accommodate a Customer's service requirements. Firm Service under this Rate Schedule is available provided that the Company determines, in its sole judgment, that adequate supply and capacity exists to accommodate a Customer's service requirements. The Company, in its sole discretion, will determine the availability of Interruptible Service under this Rate Schedule in cases where supply and capacity are adequate to provide Firm Service. A Customer request for an Interruptible Service Type will be considered on a case-by-case basis. Service under this Rate Schedule cannot be combined with service under any other Rate Schedule.

SPECIAL CONDITIONS FOR INTERRUPTIBLE SERVICE:

Any Customer served under an Interruptible Service Type as of November 1, 2012 will be allowed to continue service on such Interruptible Service Type after November 1, 2012 for a period of five (5) consecutive PGA Years. Thereafter, the eligibility for Interruptible Service shall be determined in accordance with the "SERVICE AVAILABILITY" and "DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE" provisions of this Rate Schedule. If a Customer to which this special condition applies transfers to a Firm Service Type in accordance with the "OUT-OF-CYCLE TRANSFERS" or "ANNUAL SERVICE ELECTION DATE" provisions of this Rate Schedule before the end of five (5) PGA Years, then any subsequent request for Interruptible Service will be subject to the conditions for approval as set forth above under "SERVICE AVAILABILITY".

Comment [NU1]: These changes bring this section back to the current tariff language.

This special condition will carry to any subsequent Customer at the same service address following a change in business name or a change of ownership. In all other situations, a subsequent Customer must submit a Service Election Form to request Interruptible Service, subject to approval as set forth above under "SERVICE AVAILABILITY".

APPLICATION FOR SERVICE AND SELECTION OF RATE SCHEDULE AND SERVICE TYPES:

An application for service must be made in accordance with the provisions of **Rule 2** of this Tariff, including the requirements to establish or re-establish credit.

It is the responsibility of the Customer to select the Rate Schedule and Service Type that best meets the Customer's individual service requirements. A Customer's Service Type must be stated on the Service Election Form, and is subject to the Company's approval as described in "SERVICE SELECTIONS – PROCESS AND PROCEDURE" of this Rate Schedule and in the Company's applicable policies and procedures.

PRE-REQUISITES TO SERVICE:

1. A Customer may be required to pay the Company, in advance, for costs related to the Company's installation of any new or additional Distribution Facilities necessary to provide service to Customer under this Rate Schedule. See **Schedule X**.
2. When the installation of new or additional Distribution Facilities is necessary to provide service to Customer, the Company may require Customer enter into a written service agreement.

(continue to Sheet 32-2)

Issued December 30, 2011 Effective with service on
NWN Advice No. OPUC 11-19 and after February 1, 2012

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE:

Service under this Rate Schedule requires one Service Type Selection per billing meter set assembly. All Service Types are subject to approval by the Company. The following Service Types are available under this Rate Schedule:

1. Firm Sales Service
2. Interruptible Sales Service
3. Firm Transportation Service
4. Interruptible Transportation Service
5. Combination Sales Service
6. Combination Transportation Service
7. Combination Sales and Transportation Service

The respective requirements of each Service Type are described below and elsewhere in this Rate Schedule, including, without limitation," PRE-REQUISITES TO SERVICE":

Sales Service Types:

Firm Sales Service. This is Firm Service on the Company's Distribution System. The availability of this service is dependent upon the Company's determination that adequate supply and capacity exists to provide Firm Service to the Customer. The Commodity Component applicable to gas usage is as set forth in the "ANNUAL SERVICE ELECTION DATE" provision of this Rate Schedule. Customer must select one of two Pipeline Capacity Charge options:

(a) **Volumetric.** For the volumetric choice, the rate stated for the Firm Pipeline Capacity Charge – Volumetric option in the Monthly Rates provision of this Rate Schedule is multiplied by all therms used by Customer each Billing Month.
(b) **Maximum Daily Delivery Volume (MDDV)**. For the MDDV choice, each therm of Customer's MDDV is multiplied by the Firm Pipeline Capacity Charge- Peak Demand option each Billing Month. The provisions for determination of a Customer's MDDV are described under "DETERMINATION OF MDDV" in this Rate Schedule.

Interruptible Sales Service. This is Interruptible Service on the Company's Distribution System and is subject to Curtailment of Service, as set forth in **Rule 13** and **Rule 14** of this Tariff. The Commodity Component applicable to gas usage is as set forth in the "ANNUAL SERVICE ELECTION" provision of this Rate Schedule. ~~The initial term for an Interruptible Sales Service option is five (5) consecutive PGA Years. Thereafter, Interruptible Sales Service may continue on a year-to-year basis, subject to approval by the Company under the "SERVICE AVAILABILITY" provisions of this Rate Schedule. The determination for continued service shall be made coincident with the "ANNUAL SERVICE ELECTION DATE" to be effective November 1. Should a Customer transfer to a Firm Service Type before the end of the initial term and subsequently request Interruptible Sales Service, then the request will be subject to approval by the Company and if approved, a new initial term will begin.~~

(continue to Sheet 32-4)

ORDER NO. 12 406

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

DESCRIPTION OF SERVICE TYPES AND REQUIREMENTS FOR SERVICE (continued):

Transportation Service Types:

Firm Transportation Service. This is Firm Service on the Company's Distribution System. The availability of this service is dependent upon the Company's determination that adequate capacity exists to provide Firm Service to the Customer.

Interruptible Transportation Service. This is Interruptible Service on the Company's Distribution System and is subject to Curtailment of Service, as set forth in **Rule 13** and **Rule 14** of this Tariff. ~~The initial term for an Interruptible Transportation Service option is five (5) PGA Years. Thereafter, Interruptible Transportation Service may continue on a year-to-year basis, subject to approval by the Company under the "SERVICE AVAILABILITY" provisions of this Rate Schedule. The determination for continued service shall be made coincident with the "ANNUAL SERVICE ELECTION DATE" to be effective November 1. Should a Customer transfer to a Firm Service Type before the end of the initial term and subsequently request Interruptible Sales Service, then the request will be subject to approval by the Company and if approved, a new initial term will begin.~~

Customer must secure the purchase and delivery of gas supplies to be transported on the Company's Distribution System from an Authorized Supplier/Agent of Customer's choosing. Customer must complete the Company's Transportation Service: Supplier/Agent Authorization Form and name such Authorized Supplier/Agent not less than five (5) Business Days prior to the effective date of service. The Transportation of Customer-owned gas supplies is governed by the Terms and Conditions set forth in **Schedule T** of this Tariff, and the Company's Gas Transportation Operating Policies and Procedures.

Combination Service Types:
For all Combination Service Types, Customer must specify the exact daily delivery volume to be billed for the Service Type that is billed first through the meter. Customer may choose to specify an hourly delivery volume on the Service Election Form. An hourly delivery volume that exceeds 1/24 of the MDDV does not supersede the specified MDDV.

~~The initial term for a Combination Service Type that included Interruptible Sales or Interruptible Transportation Service is five (5) PGA Years. Thereafter, the Interruptible Service portion of the Combination Service Type may continue on a year-to-year basis, subject to approval by the Company under the "SERVICE AVAILABILITY" provisions of this Rate Schedule. The determination for continued service shall be made coincident with the "ANNUAL SERVICE ELECTION DATE" to be effective November 1. Should a Customer transfer to a Firm Service Type before the end of the initial term and subsequently request Interruptible Sales Service, then the request will be subject to approval by the Company and if approved, a new initial term will begin.~~

(continue to Sheet 32-5)

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

SERVICE TYPE SELECTION – PROCESS AND PROCEDURE (continued):
When considering each Service Type request under this Rate Schedule, approval will be based upon the Company's determination, in its sole judgment, that: (a) adequate supply and capacity is available to accommodate any request for Firm Service, ~~(b) there is a system benefit or other reasonable basis upon which to approve a request for Interruptible Service, if applicable, and~~ (bc) Customer has satisfactorily established or has satisfactorily re-established credit under the terms and conditions of Rule **2** of this Tariff.

A Customer that is approved for an Interruptible Service Type **must** complete the Company's Customer Emergency Contact List Form stating the names and telephone numbers for all authorized emergency contacts. At least one authorized emergency contact must be accessible for notification 24-hours per day, 7-days per week. Following each Annual Service Election Date, the Company will provide the Customer Emergency Contact List Form to Customers that elected an Interruptible Service Type. It is the Customer's responsibility to notify the Company within five (5) Business Days of any change to Customer's authorized emergency contact information. The Company will provide the required Customer Emergency Contact List Form to Customer upon request.

ANNUAL SERVICE ELECTION DATE– July 31 Election for November 1 Service:
The Annual Service Election Date is the date by which a Customer may request to change all or a portion of their current Service Type to be effective the following November 1 through October 31 period (PGA Year). Except for a change in Rate Schedule, or an election of Winter Sales WACOG, any out-of-cycle transfer approved to be effective after the Annual Service Election Date but prior to the start of the new PGA Year will automatically terminate on October 31.

To request a change in Service Type under this provision, Customer must complete and submit the Service Election Form in accordance with the terms and conditions of the 'SERVICE TYPE SELECTION – PROCESS AND PROCEDURE" provision of this Rate Schedule. A Customer need not submit a Service Election Form for the next PGA Year if the Customer desires to retain the Service Type Selection that is in effect on July 31.

The following changes may be requested under this provision:

Change in Sales Service Type
(1) Change in Transportation Service Type
(3) Transfer to a Sales Service Type
(4) Transfer to a Transportation Service Type
(5) Selection of a Combination Service Type
(6) Selection of Winter Sales WACOG (Sales Service Types only);
(7) Change in Pipeline Capacity Charge billing option (Firm Sales Service Type only)
(8) Change to Firm Sales Service Maximum Daily Delivery Volume (MDDV) (Combination Service Type only)
(9) Change in Rate Schedule

Requests to transfer to a Sales Service Type or to change a Sales Service Type are subject to the Company's determination that such service is available at the requested location based on the conditions set forth in the "SERVICE AVAILABILITY" provision of this Rate Schedule.

Transfers between Sales Service and Transportation Service are further subject to the "APPLICATION OF TEMPORARY ADJUSTMENTS TO RATES (ACCOUNT 191 ADJUSTMENTS)" provision of this Rate Schedule.

(continue to Sheet 32-8)

UG 221

Second Partial Stipulation

Exhibit B

Stipulated Rate Spread

Stipulated Proposal At Various Increase Amounts

Rate Schedule/Class	Test Year Margin ($000)	Gas Cost	NWN Proposed Increase ($000)	Percent Margin Increase	Percent Overall Increase	Stipulated 5% Margin Decrease to Certain Classes	Assign Decrease to Other Classes Using Margin	Incremental Margin Increase	Incremental Overall Increase	$10 Million Increase NWN	$10 Million Increase NWIGU	$12.5 Million Increase NWN	$12.5 Million Increase NWIGU	$15.0 Million Increase NWN	$15.0 Million Increase NWIGU
2R	$189,469	$212,774	$33,532	17.7%	8.3%	$0	$843	0.4%	0.2%	$7,179	$8,023	$8,974	$9,817	$10,769	$11,612
3C Firm Sales	$57,759	$91,402	$8,779	15.2%	5.9%	$0	$257	0.4%	0.2%	$2,189	$2,446	$2,736	$2,993	$3,283	$3,540
31 Firm Sales	$1,362	$2,539	$207	15.2%	5.3%	$0	$6	0.4%	0.2%	$52	$58	$65	$71	$77	$83
31G Firm Sales	$15,322	$36,662	$1,164	7.6%	2.2%	$0	$68	0.4%	0.1%	$581	$649	$726	$794	$871	$939
31C Firm Trans	$81	$0	$0	0.0%	0.0%	-$4	$0	-5.0%	-5.0%	$0	-$4	$0	-$4	$0	-$4
31C Interr Sales	$285	$675	$0	0.0%	0.0%	-$14	$0	-5.0%	-1.5%	$0	-$14	$0	-$14	$0	-$14
31I Firm Sales	$3,562	$10,185	$0	0.0%	0.0%	-$178	$0	-5.0%	-1.3%	$0	-$178	$0	-$178	$0	-$178
31I Firm Trans	$183	$0	$0	0.0%	0.0%	-$9	$0	-5.0%	-5.0%	$0	-$9	$0	-$9	$0	-$9
31I Interr Sales	$76	$152	$0	0.0%	0.0%	-$4	$0	-5.0%	-1.7%	$0	-$4	$0	-$4	$0	-$4
32C Firm Sales	$2,061	$6,849	$0	0.0%	0.0%	-$103	$0	-5.0%	-1.2%	$0	-$103	$0	-$103	$0	-$103
32I Firm Sales	$2,056	$6,989	$0	0.0%	0.0%	-$103	$0	-5.0%	-1.1%	$0	-$103	$0	-$103	$0	-$103
32 Firm Trans	$3,946	$0	$0	0.0%	0.0%	-$197	$0	-5.0%	-5.0%	$0	-$197	$0	-$197	$0	-$197
32C Interr Sales	$1,749	$10,336	$0	0.0%	0.0%	-$87	$0	-5.0%	-0.7%	$0	-$87	$0	-$87	$0	-$87
32I Interr Sales	$2,647	$16,476	$0	0.0%	0.0%	-$132	$0	-5.0%	-0.7%	$0	-$132	$0	-$132	$0	-$132
32 Interr Trans	$6,847		$0	0.0%	0.0%	-$342	$0	-5.0%	-5.0%	$0	-$342	$0	-$342	$0	-$342
Total:	$287,405	$395,039	$43,682	15.2%	6.4%	-$1,175	$1,175			$10,000	$10,000	$12,500	$12,500	$15,000	$15,000
										10000		12500		15000	

NOTE: By stipulation, Schedules 1R and 1C have been eliminated, with the former's customers moved into Schedule 2R and the latter's moved into Schedule 3C.

31/32 Subclasse -5%

Rate Spread Comparison - NWN v NWIGU at Various Increase Amounts

Customer Class	Overall Percentage Change NWN $10M	$12.5M	$15.0M	NWIGU $10M	$12.5M	$15.0M	Margin Percentage Change NWN $10 M	$12.5M	$15.0M	NWIGU $10M	$12.5M	$15.0M
2R	1.8%	2.2%	2.7%	2.0%	2.4%	2.9%	3.8%	4.7%	5.7%	4.2%	5.2%	6.1%
3C Firm Sales	1.5%	1.8%	2.2%	1.6%	2.0%	2.4%	3.8%	4.7%	5.7%	4.2%	5.2%	6.1%
31 Firm Sales	1.3%	1.7%	2.0%	1.5%	1.8%	2.1%	3.8%	4.7%	5.7%	4.2%	5.2%	6.1%
31C Firm Sales	1.1%	1.4%	1.7%	1.2%	1.5%	1.8%	3.8%	4.7%	5.7%	4.2%	5.2%	6.1%
31C Firm Trans	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
31C Interr Sales	0.0%	0.0%	0.0%	-1.5%	-1.5%	-1.5%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
31I Firm Sales	0.0%	0.0%	0.0%	-1.3%	-1.3%	-1.3%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
31I Firm Trans	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
31I Interr Sales	0.0%	0.0%	0.0%	-1.7%	-1.7%	-1.7%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
32C Firm Sales	0.0%	0.0%	0.0%	-1.2%	-1.2%	-1.2%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
32I Firm Sales	0.0%	0.0%	0.0%	-1.1%	-1.1%	-1.1%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
32 Firm Trans	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
32C Interr Sales	0.0%	0.0%	0.0%	-0.7%	-0.7%	-0.7%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
32I Interr Sales	0.0%	0.0%	0.0%	-0.7%	-0.7%	-0.7%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
32 Interr Trans	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%	0.0%	0.0%	0.0%	-5.0%	-5.0%	-5.0%
Total:	1.5%	1.8%	2.2%	1.5%	1.8%	2.2%	3.5%	4.3%	5.2%	3.5%	4.3%	5.2%

ORDER NO. 12 408

NW Natural
Determination of Cost of Service

Input Capital Costs and Rates			
Cost of Capital	% of Capital	Cost	Weighted Cost
Debt	50.00%	6.33%	3.17%
Preferred Equity	0.00%	0.00%	0.00%
Common Equity	50.00%	10.00%	5.00%
	100.00%		8.17%
State Tax Rate			7.60%
Federal Tax Rate			35.00%
Revenue Sensitive Rate (held to franchise rate)			2.30%
Depreciation Rate			2.50%
Property Tax Rate			1.50%
Incremental O&M			0.0
Bonus Tax Depreciation toggled (1 yes, 2 no)			2
Investment			2,900

Indicated Multiplier (Year 1) 5.9 Using distribution margin

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
1 Depreciation		73	73	73	73	73	73	73	73	73	73	73	73
2 O&M		40	40	40	40	40	40	40	40	40	40	40	40
3 Property Taxes		43	42	41	40	39	38	37	36	34	33	32	31
Taxes on Equity Return													
4 State		18	17	16	15	15	14	13	12	12	11	10	10
5 Federal		77	73	69	66	62	59	56	53	50	47	44	41
6 Total Taxes		95	90	86	81	77	73	69	65	62	58	54	50
Return on Rate Base													
7 Debt		90	86	81	77	73	69	66	62	59	55	51	48
8 Preferred Equity		0	0	0	0	0	0	0	0	0	0	0	0
9 Common Equity		142	136	129	122	115	109	104	98	93	87	81	76
10 Total Return		233	222	210	199	188	179	169	160	151	142	133	124
11 Subtotal Cost of Service		483	467	449	432	416	402	387	374	360	346	332	318
12 Revenue Sensitive Items		11	11	11	10	10	9	9	9	8	8	8	7
13 Total Cost of Service	$4,264.95	$494	$478	$460	$442	$426	$411	$397	$382	$368	$354	$339	$325
	$4,393.46	372	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372
14 Annual Cost of Service as % of Investment		17.05%	16.49%	15.85%	15.26%	14.70%	14.18%	13.68%	13.18%	12.69%	12.20%	11.71%	11.21%
Rate Base net of deprec. & def. tax		$2,849	$2,722	$2,574	$2,436	$2,308	$2,188	$2,074	$1,962	$1,850	$1,738	$1,627	$1,515
Income Taxes													
Gross up of Equity Return		237	227	214	203	192	182	173	163	154	145	135	126
Less: State tax		18	17	16	15	15	14	13	12	12	11	10	10
Federal Taxable Income		219	209	198	187	178	168	160	151	142	134	125	117
Less: Federal Tax		77	73	69	66	62	59	56	53	50	47	44	41
Return		142	136	129	122	115	109	104	98	93	87	81	76
Deferred Taxes													
Book Depreciation		73	73	73	73	73	73	73	73	73	73	73	73
Tax Depreciation		145	276	248	223	201	181	171	171	171	171	171	171
Book Tax Difference		73	203	175	151	128	108	99	99	99	99	99	99
Tax Effect		29	81	70	60	51	43	39	39	39	39	39	39
MACRS Depreciation 15		5.00%	9.50%	8.55%	7.70%	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%	5.90%
Property Tax Base		2,878	2,806	2,733	2,661	2,588	2,516	2,443	2,371	2,298	2,226	2,153	2,081
Tax Calculation Check		0	0	0	0	0	0	0	0	0	0	0	0
MACRS Depreciation 15		5.00%	9.50%	8.55%	7.70%	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%	5.90%
MACRS Depreciation 15 Bonus		52.50%	4.75%	4.28%	3.85%	3.47%	3.12%	2.95%	2.95%	2.96%	2.95%	2.96%	2.95%
		0.3994											
		0.6006											

	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24
1 Depreciation	73	73	73	73	73	73	73	73	73	73	73	73
2 O&M	40	40	40	40	40	40	40	40	40	40	40	40
3 Property Taxes	30	29	28	27	26	25	24	23	21	20	19	18
Taxes on Equity Return												
4 State	9	8	7	7	6	6	6	6	5	5	5	5
5 Federal	38	35	32	29	28	26	25	24	23	22	21	19
6 Total Taxes	47	43	39	36	34	33	31	30	28	27	25	24
Return on Rate Base												
7 Debt	44	41	37	34	32	31	30	28	27	25	24	23
8 Preferred Equity	0	0	0	0	0	0	0	0	0	0	0	0
9 Common Equity	70	65	59	54	51	49	47	45	42	40	38	36
10 Total Return	115	105	96	89	84	80	76	73	69	66	62	59
11 Subtotal Cost of Service	304	290	276	264	256	250	244	238	231	225	219	213
12 Revenue Sensitive Items	7	7	6	6	6	6	6	6	5	5	5	5
13 Total Cost of Service	$311	$297	$282	$270	$262	$256	$249	$243	$237	$231	$224	$218
	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372
14 Annual Cost of Service as % of Investment	10.72%	10.23%	9.74%	9.31%	9.03%	8.82%	8.60%	8.39%	8.17%	7.96%	7.74%	7.53%
Rate Base net of deprec. & def. tax	$1,403	$1,291	$1,179	$1,084	$1,023	$980	$936	$893	$849	$806	$762	$718
Income Taxes												
Gross up of Equity Return	117	107	98	90	85	82	78	74	71	67	63	60
Less: State tax	9	8	7	7	6	6	6	6	5	5	5	5
Federal Taxable Income	108	99	91	83	79	75	72	69	65	62	59	55
Less: Federal Tax	38	35	32	29	28	26	25	24	23	22	21	19
Return	70	65	59	54	51	49	47	45	42	40	38	36
Deferred Taxes												
Book Depreciation	73	73	73	73	73	73	73	73	73	73	73	73
Tax Depreciation	171	171	171	86	0	0	0	0	0	0	0	0
Book Tax Difference	99	99	99	13	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
Tax Effect	39	39	39	5	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
MACRS Depreciation 15	5.91%	5.90%	5.91%	2.95%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Property Tax Base	2,008	1,936	1,863	1,791	1,718	1,646	1,573	1,501	1,428	1,356	1,283	1,211
Tax Calculation Check	0	0	0	0	0	0	0	0	0	0	0	0
MACRS Depreciation 15	5.91%	5.90%	5.91%	2.95%								
MACRS Depreciation 15 Bonus	2.96%	2.95%	2.96%	1.48%	0	0	0	0	0	0	0	0

	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	
1 Depreciation	73	73	73	73	73	73	73	73	73	73	73	73	73	2,683
2 O&M	40	40	40	40	40	40	40	40	40	40	40	40	40	
3 Property Taxes	17	16	15	14	13	12	11	9	8	7	6	5	4	
Taxes on Equity Return														
4 State	4	4	4	3	3	3	3	2	2	2	2	1	1	
5 Federal	18	17	16	15	13	12	11	10	9	8	6	5	4	
6 Total Taxes	22	21	20	18	17	15	14	12	11	9	8	7	5	
Return on Rate Base														
7 Debt	21	20	19	17	16	14	13	12	10	9	8	6	5	
8 Preferred Equity	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Common Equity	34	32	29	27	25	23	21	19	16	14	12	10	8	
10 Total Return	55	52	48	44	41	37	34	30	27	23	20	16	12	
11 Subtotal Cost of Service	207	201	195	189	183	177	171	164	158	152	146	140	134	
12 Revenue Sensitive Items	5	5	5	4	4	4	4	4	4	4	3	3	3	
13 Total Cost of Service	$212	$206	$200	$193	$187	$181	$175	$168	$162	$156	$150	$143	$137	
	$372	$372	$372	$372	$372	$372								
14 Annual Cost of Service as % of Investment	7.31%	7.10%	6.88%	6.67%	6.45%	6.24%	6.02%	5.81%	5.59%	5.38%	5.16%	4.95%	4.73%	
Rate Base net of deprec. & def. tax	$675	$631	$588	$544	$501	$457	$414	$370	$327	$283	$239	$196	$152	
Income Taxes														
Gross up of Equity Return	56	53	49	45	42	38	34	31	27	24	20	16	13	
Less: State tax	4	4	4	3	3	3	3	2	2	2	2	1	1	
Federal Taxable Income	52	49	45	42	39	35	32	28	25	22	18	15	12	
Less: Federal Tax	18	17	16	15	13	12	11	10	9	8	6	5	4	
Return	34	32	29	27	25	23	21	19	16	14	12	10	8	
Deferred Taxes														
Book Depreciation	73	73	73	73	73	73	73	73	73	73	73	73	73	
Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
Book Tax Difference	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	
Tax Effect	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	87
MACRS Depreciation 15	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Property Tax Base	1,138	1,066	993	921	848	776	703	631	558	486	413	341	268	
Tax Calculation Check	0	0	0	0	0	0	0	0	0	0	0	0	0	
MACRS Depreciation 15														
MACRS Depreciation 15 Bonus	0	0	0	0	0	0	0	0	0	0	0	0	1	

NW Natural

Income Statement		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1 Revenue - Original		371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371
2 Operations & Maintenance	$40.00	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
3 Depreciation	2.50%	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
4 Franchise Tax	2.30%	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
4 Property Tax	1.50%	(44)	(42)	(41)	(40)	(39)	(38)	(37)	(36)	(35)	(34)	(33)	(32)	(30)	(29)	(28)	(27)	(26)	(25)	(24)	(23)	(22)	(21)	(20)	(18)	(17)	(16)	(15)	(14)	(13)	(12)
5 Interest Expense	6.33%	(92)	(86)	(81)	(77)	(73)	(69)	(66)	(62)	(59)	(55)	(51)	(48)	(44)	(41)	(37)	(34)	(32)	(31)	(30)	(28)	(27)	(25)	(24)	(23)	(21)	(20)	(19)	(17)	(16)	(14)
6 Net Income Before Tax		115	121	127	133	138	143	147	152	157	161	166	170	175	180	184	188	191	194	196	199	201	204	206	209	211	214	216	219	221	224
7 Income Tax	39.94%	46	48	51	53	55	57	59	61	63	64	66	68	70	72	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89
8 Net Available to Common		69	73	76	80	83	86	88	91	94	97	100	102	105	108	111	113	115	116	118	119	121	122	124	125	127	128	130	131	133	134

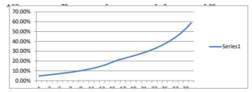
Balance Sheet	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
Assets																														
9 Gross Plant	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900
10 Accumulated Depreciation	73	145	218	290	363	435	508	580	653	725	798	870	943	1,015	1,088	1,160	1,233	1,305	1,378	1,450	1,523	1,595	1,668	1,740	1,813	1,885	1,958	2,030	2,103	2,175
11 Net Plant	2,828	2,755	2,683	2,610	2,538	2,465	2,393	2,320	2,248	2,175	2,103	2,030	1,958	1,885	1,813	1,740	1,668	1,595	1,523	1,450	1,378	1,305	1,233	1,160	1,088	1,015	943	870	798	725
12 Total Assets	2,828	2,755	2,683	2,610	2,538	2,465	2,393	2,320	2,248	2,175	2,103	2,030	1,958	1,885	1,813	1,740	1,668	1,595	1,523	1,450	1,378	1,305	1,233	1,160	1,088	1,015	943	870	798	725
Liabilities and Equity																														
13 Common Equity	1,399	1,322	1,251	1,185	1,123	1,065	1,009	953	897	841	785	729	673	617	561	523	501	479	457	435	414	392	370	348	327	305	283	261	239	218
14 Long Term Debt	1,399	1,322	1,251	1,185	1,123	1,065	1,009	953	897	841	785	729	673	617	561	523	501	479	457	435	414	392	370	348	327	305	283	261	239	218
15 Deferred Taxes	29	110	180	240	292	335	374	414	453	492	532	571	611	650	690	695	666	637	608	579	550	521	492	463	434	405	376	347	319	290
16 Total Liabilities and Equity	2,828	2,755	2,683	2,610	2,538	2,465	2,393	2,320	2,248	2,175	2,103	2,030	1,958	1,885	1,813	1,740	1,668	1,595	1,523	1,450	1,378	1,305	1,233	1,160	1,088	1,015	943	870	798	725

Cash Flow Statement	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
Operating Activities																														
1 Net Income	69	73	76	80	83	86	88	91	94	97	100	102	105	108	111	113	115	116	118	119	121	122	124	125	127	128	130	131	133	134
2 Depreciation	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
3 Deferred Taxes	29	81	70	60	51	43	39	39	39	39	39	39	39	39	39	5	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
4 Cash Provided by Operating Activities	170	226	219	212	207	201	200	203	206	209	212	214	217	220	223	191	159	160	162	163	164	166	167	169	170	172	173	175	176	178
Investing Activities																														
5 Project	(2,900)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Cash Used in Investing Activities	(2,900)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financing Activities																														
7 Common Stock Issued	1,450	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Long Term Debt Issued	1,450	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Long Term Debt Retired	(51)	(77)	(71)	(66)	(62)	(58)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(39)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
10 Common Stock Dividends	(120)	(150)	(148)	(146)	(145)	(144)	(144)	(147)	(150)	(153)	(156)	(158)	(161)	(164)	(167)	(152)	(137)	(138)	(140)	(141)	(143)	(144)	(146)	(147)	(149)	(150)	(152)	(153)	(155)	(156)
11 Cash Provided by Financing Activities	2,730	(226)	(219)	(212)	(207)	(201)	(200)	(203)	(206)	(209)	(212)	(214)	(217)	(220)	(223)	(191)	(159)	(160)	(162)	(163)	(164)	(166)	(167)	(169)	(170)	(172)	(173)	(175)	(176)	(178)
12 Net Cash Flow	0	(0)	0	0	0	0	0	0	0	0	0	(0)	0	0	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Financial Ratios	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
13 ROI (Net Op Inc/Avg Rate Base)	5.64%	5.84%	6.13%	6.43%	6.75%	7.08%	7.43%	7.82%	8.25%	8.74%	9.29%	9.93%	10.66%	11.53%	12.56%	13.61%	14.40%	15.05%	15.77%	16.55%	17.41%	18.36%	19.42%	20.61%	21.96%	23.49%	25.25%	27.29%	29.68%	32.53%
14 Return on Average Equity	4.83%	5.36%	5.94%	6.54%	7.17%	7.83%	8.53%	9.30%	10.17%	11.14%	12.25%	13.52%	15.00%	16.73%	18.79%	20.89%	22.48%	23.78%	25.20%	26.76%	28.48%	30.39%	32.52%	34.90%	37.59%	40.65%	44.17%	48.24%	53.03%	58.73%
15 Total Debt to Total Capital (Year-end)	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
16 Interest Coverage (EBIT/Interest)	2.24	2.41	2.56	2.72	2.89	3.08	3.24	3.45	3.67	3.93	4.22	4.56	4.94	5.40	5.94	6.49	6.91	7.26	7.63	8.04	8.49	8.99	9.56	10.18	10.89	11.69	12.62	13.69	14.95	16.45
17 FFO to Total Debt		16.64%	17.02%	17.44%	17.90%	18.41%	19.32%	20.71%	22.27%	24.01%	26.02%	28.30%	30.97%	34.07%	37.79%	35.23%	30.99%	32.67%	34.50%	36.52%	38.74%	41.20%	43.94%	47.02%	50.49%	54.44%	58.98%	64.24%	70.42%	77.78%
18 FFO Interest Coverage	2.86	3.63	3.69	3.75	3.83	3.91	4.05	4.27	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6.38	6.97	6.56	5.90	6.16	6.45	6.77	7.12	7.51	7.94	8.43	8.98	9.60	10.32	11.15	12.12	13.29

			investment	times margin
19 IRR	5 year	-22.2%	872	2.35
20 IRR	10 year	-2.7%	1,582	4.26
21 IRR	15 year	3.3%	2,145	5.78
22 IRR	20 year	5.3%	2,490	6.71
23 IRR	25 year	6.3%	2,725	7.35
24 IRR	30 year	6.9%	2,900	7.82

2,900 Input Investment calibrate at 6.9 ROR



IRR Calculation	($2,900)	225	278	268	259	250	243	240	240	241	242	243	243	244	244	245	212	178	179	179	180	181	181	182	183	183	184	185	185	186	186

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1 Revenue		371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371	371
2 Operations & Maintenance		(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
3 Franchise Tax	2.30%	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
4 Property Tax	1.50%	(44)	(42)	(41)	(40)	(39)	(38)	(37)	(36)	(35)	(34)	(33)	(32)	(30)	(29)	(28)	(27)	(26)	(25)	(24)	(23)	(22)	(21)	(20)	(18)	(17)	(16)	(15)	(14)	(13)	(12)
5 Net Before Taxes		279	280	281	282	283	284	285	287	288	289	290	291	292	293	294	295	296	297	299	300	301	302	303	304	305	306	307	308	309	311
6 Income Tax	39.94%	111	112	112	113	113	114	114	114	115	115	116	116	117	117	118	118	118	119	119	120	120	121	121	121	122	122	123	123	124	124
7 Net After Tax		168	168	169	170	170	171	171	172	173	173	174	175	175	176	177	177	178	179	179	180	181	181	182	183	183	184	185	185	186	186
8 Tax Benefit on Interest																															
9 Tax Benefit on Investment		58	110	99	89	80	72	68	68	68	68	68	68	68	68	68	34	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Total Operating Cash (ROR Analysis)		225	278	268	259	250	243	240	240	241	242	243	243	244	244	245	212	178	179	179	180	181	181	182	183	183	184	185	185	186	186
		170																													
		115																													

Plant Additions	Rate	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1 Plant		2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900	2,900
2 Depreciation	2.50%	(73)	(145)	(218)	(290)	(363)	(435)	(508)	(580)	(653)	(725)	(798)	(870)	(943)	(1,015)	(1,088)	(1,160)	(1,233)	(1,305)	(1,378)	(1,450)	(1,523)	(1,595)	(1,668)	(1,740)	(1,813)	(1,885)	(1,958)	(2,030)	(2,103)	(2,175)
3 Net Plant		2,828	2,755	2,683	2,610	2,538	2,465	2,393	2,320	2,248	2,175	2,103	2,030	1,958	1,885	1,813	1,740	1,668	1,595	1,523	1,450	1,378	1,305	1,233	1,160	1,088	1,015	943	870	798	725
4 Deferred Taxes		29	110	180	240	292	335	374	414	453	492	532	571	611	650	690	695	666	637	608	579	550	521	492	463	434	405	376	347	319	290
5 Net Rate Base		2,799	2,645	2,502	2,370	2,246	2,130	2,018	1,906	1,794	1,683	1,571	1,459	1,347	1,235	1,123	1,045	1,002	958	914	871	827	784	740	697	653	610	566	523	479	435
6 Average Rate Base		2,849	2,722	2,574	2,436	2,308	2,188	2,074	1,962	1,850	1,738	1,627	1,515	1,403	1,291	1,179	1,084	1,023	980	936	893	849	806	762	718	675	631	588	544	501	457
DEBT	Rate																														
7 New Debt		1,450	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Beginning Debt		0	1,399	1,322	1,251	1,185	1,123	1,065	1,009	953	897	841	785	729	673	617	561	523	501	479	457	435	414	392	370	348	327	305	283	261	239
9 Principal Payment		(51)	(77)	(71)	(66)	(62)	(58)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(39)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
10 Ending Debt		1,399	1,322	1,251	1,185	1,123	1,065	1,009	953	897	841	785	729	673	617	561	523	501	479	457	435	414	392	370	348	327	305	283	261	239	218
11 Total Payment		(41)	9	10	11	11	11	10	6	3	(1)	(5)	(8)	(12)	(15)	(19)	(5)	11	9	8	6	5	4	2	1	(0)	(2)	(3)	(5)	(6)	(7)
12 Interest	6.330%	92	86	81	77	73	69	66	62	59	55	51	48	44	41	37	34	32	31	30	28	27	25	24	23	21	20	19	17	16	14
EQUITY																															
13 Paid in		1,450	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 Beginning Equity		0	1,399	1,322	1,251	1,185	1,123	1,065	1,009	953	897	841	785	729	673	617	561	523	501	479	457	435	414	392	370	348	327	305	283	261	239
15 Excess Dividend	(Net Inc)	(120)	(150)	(148)	(146)	(145)	(144)	(144)	(147)	(150)	(153)	(156)	(158)	(161)	(164)	(167)	(152)	(137)	(138)	(140)	(141)	(143)	(144)	(146)	(147)	(149)	(150)	(152)	(153)	(155)	(156)
16 Net Income		69	73	76	80	83	86	88	91	94	97	100	102	105	108	111	113	115	116	118	119	121	122	124	125	127	128	130	131	133	134
17 Ending Equity		1,399	1,322	1,251	1,185	1,123	1,065	1,009	953	897	841	785	729	673	617	561	523	501	479	457	435	414	392	370	348	327	305	283	261	239	218
18 Average Equity		1,425	1,361	1,287	1,218	1,154	1,094	1,037	981	925	869	813	757	701	645	589	542	512	490	468	446	425	403	381	359	337	316	294	272	250	229

Tax Depreciation		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Total
1 Tax Depreciation Rate		5.00%	9.50%	8.55%	7.70%	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	2.95%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
2 Plant Additions		2,900																														
3 Total Tax Depreciation		145	276	248	223	201	181	171	171	171	171	171	171	171	171	171	86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Tax Benefit @	39.94%	58	110	99	89	80	72	68	68	68	68	68	68	68	68	68	34	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Book Depreciation																																
5 Book Depreciation Rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
6 Plant Additions		2,900																														
7 Book Depreciation		73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	2,175
8 Total Book Depreciation		73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	2,175
9 Total Tax Depreciation		145	276	248	223	201	181	171	171	171	171	171	171	171	171	171	86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Difference		73	203	175	151	128	108	99	99	99	99	99	99	99	99	99	13	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(2,175)
11 Deferred Taxes	39.94%	29	81	70	60	51	43	39	39	39	39	39	39	39	39	39	5	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	290
15 year MACRS		5.00%	9.50%	8.55%	7.70%	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	2.95%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

	Capital Structure	Cost Rate	Cost	After-tax Cost
Debt	50.00%	6.33%	3.17%	1.90%
Preferred	0.00%	0.00%	0.00%	
Equity	50.00%	10.00%	5.00%	5.00%
	100.00%		8.17%	6.90%

Construction Costs 2,900

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of John D. Taylor

LINE EXTENSION POLICY
EXHIBIT 1803

June 6, 2022

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 Coalition DR 33

33. Please provide all documents relevant to the calculation of allowances described in Tariff Schedule X: Distribution Facilities Extension For Applicant-Requested Services And Mains.

Response:

The Coalition states that it uses the word "document" in its data requests to have "the broadest possible meaning and includes but is not limited to, the original or any copy of any accounting record and worksheet, agreement, book, bill, calendar, chart, contract, correspondence, data sheet or data processing card, diary, drawing, electronic file, estimate, graph, index, inventory, invoice, letter, log, mag card, map, memorandum, minutes of meetings, notes, pamphlet, paper, periodical, printout, purchase order, receipt, record, report, schedule, study, summary, tape, telegrams, working paper, writing, or any other written, recorded, transcribed, punched, taped, filmed, photographic or graphic matter, whether in physical format or electronically stored information, however produced or reproduced, to which you now have or at any time have had access."

The Company objects to this data request under 860-001-0500 because the request for "all documents" is burdensome, overly broad and not commensurate with the needs of this case, the resources available to the parties or the importance of the issues to which the discovery relates. Notwithstanding this objection, the Company responds as follows:

Please see the Company's response to UG 435 CUB DR 52 and its Attachment 1.

For commercial allowances, the Company calculates the allowance using a proprietary software program called Experlogix. This program calculates the construction allowance based on Schedule X, under X.6 Non-Residential and Planned Developments:

> The Company will perform an investment analysis for each installation to determine the amount of any Construction Allowance. At a minimum, the Construction Allowance will equal 5.0 times the annual margin revenue that is estimated to be generated from the operation of natural gas-fired equipment to

be installed at the service address. The Company will estimate therm usage associated with the operation of gas-fired equipment based on structure characteristics, the type and frequency of use of the gas-fired equipment, and the nameplate rating of the gas-fired equipment to be installed.

Supplemental Response

In response to NW Natural's UG 435 Coalition DR 33, the Coalition requested NW Natural to supplement its response to UG 435 Coalition DR 33 to "specifically request all calculations, reports or analysis used to develop the allowances."

NW Natural restates that UG 435 CUB DR 52 Attachment 1 is the financial model that was used to establish the Schedule X line extension allowances for residential customers. In our response to UG 435 CUB 52, NW Natural explained:

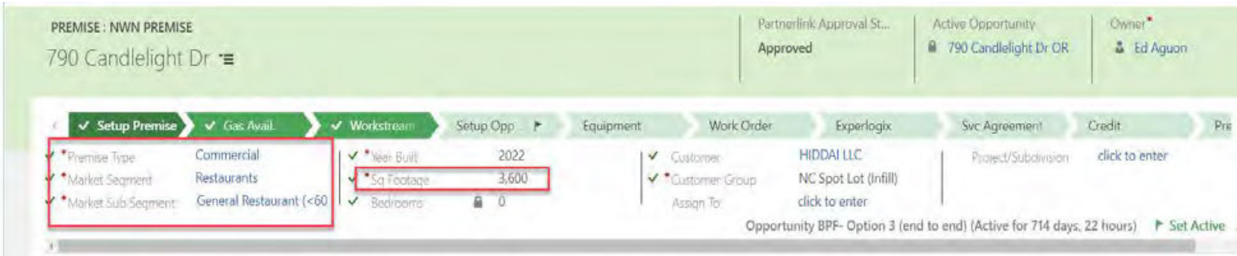
> "Please see attached file named "UG 435 CUB DR 52 Attachment 1.xlsx." Note that this file produced the construction allowances as filed in the general rate case UG-221, and not the allowances that are quantified in Schedule X of the tariff. The changes that were proposed in the Company's filing in UG 221 were approved in Order 12-408 (page 8), which adopted the Second Partial Stipulation in the docket. Order 12-408 is attached as "UG 435 CUB DR 52 Attachment 2.pdf." The allowances that are in Schedule X of the tariff are slightly lower than the filed amounts due to the lower resulting revenue requirement after processing the case, but the methodology to produce the allowances was the same. The allowances have not been adjusted in subsequent cases.
>
> The methodology used to determine the allowances was to set the construction cost or allowable such that a revenue stream for different terms created an internal rate of return (IRR) set at the Company's cost of capital. The revenue stream assumed billing on a Straight-Fixed-Variable (SFV) rate design that was proposed in the Company's rate case filing. For Category A in the tariff, the revenue stream was assumed for 30 years; for Category B, the revenue stream was assumed for 15 years, and for Category C, the revenue stream was assumed for 5 years. The 30-, 15-, and 5-year terms were used based on an assumption that a customer having gas space heating would remain a customer for 30 years, and so on."

If the Coalition would like a demonstration of how the model works, please reach out to counsel for NW Natural.

With respect to Schedule X's application to commercial customers, NW Natural calculates the line extension allowance in a program called Experlogix, which calculates the construction allowance based on Schedule X, under X.6 Non-Residential and Planned Developments. We are unable to send this program outside of the Company. Below are screen shots of how the program works and calculates the allowance.

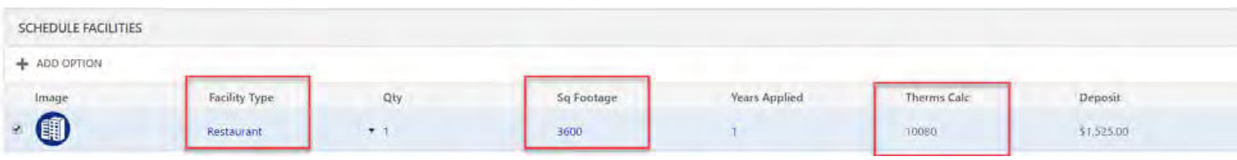
Step 1:

- A commercial premise is identified by market segment. In this example a restaurant. The market segment and square footage will be used in the financial modeling



Step 2:

- When creating the financial model, a facility type that matches the market segment is selected from a group of facility types. We choose the one that best represents our market segment; Restaurant.



Step 3:

- The facility types co-efficient is multiplied by the square footage to determine annual therm load. (See Step 4, incremental therms on results)
- The co-efficient is a historical representation of actual usage of like billing facilities

Step 4:

- 2.8 (co-efficient for restaurant) X 3600 (Square feet) = 10,080 annual therms

- Annual meter charge of $180 ($15/month for 1 year on commercial premise – see Rate Schedule 3)
- Take the delivery margin per therm of $0.57371 X 10,080 annual therms which equals $5,783 + $180 (annual meter charge)= $5963 (annual estimated margin)
- $5,963 (annual estimated margin) X 5 years (margin multiplier – 5X margin) = $29,815 which is your construction allowance

As mentioned above, we are unable to isolate Experlogix and send it independently. It is currently imbedded within our CRM system and is not a stand-alone program. If you would like a demonstration of how Experlogix works, please reach out to counsel for NW Natural.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of John D. Taylor

LINE EXTENSION POLICY EXHIBIT 1804

This exhibit is being filed in its native, Excel format.

June 6, 2022

NW Natural
Determination of Cost of Service

Input Capital Costs and Rates

Cost of Capital	% of Capital	Cost	Weighted Cost
Debt	50.00%	4.271%	2.136%
Common Equity	50.00%	9.400%	4.700%
	100.00%		6.836%
State Tax Rate			7.60%
Federal Tax Rate			21.00%
Revenue Sensitive Rate (Franchise tax, Comm fee)			2.741%
Depreciation Rate			2.50%
Property Tax Rate			1.50%
Incremental O&M			79.19
Investment			3 790

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
1 Depreciation	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
2 O&M	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
3 Property Taxes	56	55	53	52	51	49	48	46	45	43	42	41	39	38	36	35	33	32	31
Taxes on Equity Return																			
4 State	18	18	17	16	16	15	14	14	13	13	12	12	11	11	10	9	9	8	8
5 Federal	47	45	43	42	40	38	37	36	34	33	31	30	28	27	25	24	23	21	20
6 Total Taxes	65	63	60	58	56	54	51	49	47	45	43	41	39	37	35	33	31	29	27
Return on Rate Base																			
7 Debt	80	77	74	71	68	66	63	61	58	56	53	51	48	46	44	41	39	36	34
8 Common Equity	176	170	163	157	151	145	139	134	128	123	117	112	107	101	96	90	85	80	74
9 Total Return	255	247	237	228	219	211	202	194	186	179	171	163	155	147	139	131	124	116	108
10 Subtotal Cost of Service	551	538	525	512	499	487	475	464	453	441	430	419	408	396	385	374	362	351	340
11 Revenue Sensitive Items	16	15	15	14	14	14	13	13	13	12	12	12	11	11	11	11	10	10	10
12 Total Cost of Service	$566	$554	$540	$526	$513	$501	$489	$477	$465	$454	$442	$431	$419	$407	$396	$384	$373	$361	$350
Rate Base net of deprec. & def. tax	$3 736	$3 611	$3 471	$3 336	$3 206	$3 080	$2 959	$2 842	$2 727	$2 612	$2 497	$2 382	$2 267	$2 152	$2 038	$1 923	$1 808	$1 693	$1 578
Income Taxes																			
Gross up of Equity Return	241	232	223	215	206	198	191	183	176	168	161	153	146	139	131	124	116	109	102
Less: State tax	18	18	17	16	16	15	14	14	13	13	12	12	11	11	10	9	9	8	8
Federal Taxable Income	222	215	206	198	191	183	176	169	162	155	149	142	135	128	121	114	108	101	94
Less: Federal Tax	47	45	43	42	40	38	37	36	34	33	31	30	28	27	25	24	23	21	20
Return	176	170	163	157	151	145	139	134	128	123	117	112	107	101	96	90	85	80	74
Deferred Taxes																			
Book Depreciation	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Tax Depreciation	142	274	253	234	217	200	185	171	169	169	169	169	169	169	169	169	169	169	169
Book Tax Difference	47	179	158	139	122	106	91	77	74	74	74	74	74	74	74	74	74	74	74
Tax Effect	13	48	43	38	33	29	24	21	20	20	20	20	20	20	20	20	20	20	20
MACRS Depreciation 20	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
Property Tax Base	3 749	3 654	3 560	3 465	3 370	3 275	3 181	3 086	2 991	2 896	2 802	2 707	2 612	2 517	2 423	2 328	2 233	2 138	2 044
Tax Calculation Check	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	27.004%																		
	0.72996																		

	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	
1 Depreciation	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	3 506
2 O&M	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	
3 Property Taxes	29	28	26	25	24	22	21	19	18	16	15	14	12	11	9	8	6	5	
Taxes on Equity Return																			
4 State	7	7	6	6	6	5	5	5	4	4	4	3	3	3	2	2	2	1	
5 Federal	18	17	16	15	14	13	13	12	11	10	9	8	7	6	6	5	4	3	
6 Total Taxes	25	24	22	21	20	19	17	16	15	14	13	11	10	9	8	7	5	4	
Return on Rate Base																			
7 Debt	31	29	27	26	24	23	21	20	18	17	16	14	13	11	10	8	7	5	
8 Common Equity	69	64	60	57	54	50	47	44	41	37	34	31	28	24	21	18	15	11	
9 Total Return	100	93	87	83	78	73	69	64	59	54	50	45	40	35	31	26	21	17	
10 Subtotal Cost of Service	329	318	310	303	295	288	281	273	266	259	251	244	237	229	222	214	207	200	
11 Revenue Sensitive Items	9	9	9	9	8	8	8	8	7	7	7	7	7	6	6	6	6	6	
12 Total Cost of Service	$338	$327	$319	$311	$304	$296	$289	$281	$273	$266	$258	$251	$243	$236	$228	$221	$213	$205	
Rate Base net of deprec. & def. tax	$1 464	$1 360	$1 280	$1 210	$1 141	$1 072	$1 003	$934	$865	$795	$726	$657	$588	$519	$450	$380	$311	$242	
Income Taxes																			
Gross up of Equity Return	94	88	82	78	73	69	65	60	56	51	47	42	38	33	29	24	20	16	
Less: State tax	7	7	6	6	6	5	5	5	4	4	4	3	3	3	2	2	2	1	
Federal Taxable Income	87	81	76	72	68	64	60	56	51	47	43	39	35	31	27	23	19	14	
Less: Federal Tax	18	17	16	15	14	13	13	12	11	10	9	8	7	6	6	5	4	3	
Return	69	64	60	57	54	50	47	44	41	37	34	31	28	24	21	18	15	11	
Deferred Taxes																			
Book Depreciation	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	
Tax Depreciation	169	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Book Tax Difference	74	(10)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	
Tax Effect	20	(3)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	77
MACRS Depreciation 20	4.46%	2.23%	0.00%																
Property Tax Base	1 949	1 854	1 759	1 665	1 570	1 475	1 380	1 286	1 191	1 096	1 001	907	812	717	622	528	433	338	
Tax Calculation Check	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Income Statement		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1 Revenue		462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462
2 Operations & Maintenance	$79.19	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
3 Depreciation	2.50%	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)
4 Franchise Tax	2.74%	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
4 Property Tax	1.50%	(57)	(55)	(54)	(53)	(51)	(50)	(48)	(47)	(45)	(44)	(43)	(41)	(40)	(38)	(37)	(36)	(34)	(33)	(31)	(30)	(28)	(27)	(26)	(24)	(23)	(21)	(20)	(18)	(17)	(16)
5 Interest Expense	4.27%	(81)	(77)	(74)	(71)	(68)	(66)	(63)	(61)	(58)	(56)	(53)	(51)	(48)	(46)	(44)	(41)	(39)	(36)	(34)	(31)	(29)	(28)	(26)	(25)	(23)	(22)	(20)	(19)	(17)	(16)
6 Net Income Before Tax		137	143	147	151	156	160	164	168	171	175	179	183	187	191	195	199	202	206	210	214	218	221	224	226	229	232	235	238	241	244
7 Income Tax	27.00%	37	39	40	41	42	43	44	45	46	47	48	49	50	52	53	54	55	56	57	58	59	60	60	61	62	63	63	64	65	66
8 Net Available to Common		100	104	107	111	114	117	119	122	125	128	131	134	136	139	142	145	148	151	153	156	159	161	163	165	167	170	172	174	176	178

Balance Sheet	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
Assets																														
9 Gross Plant	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790
10 Accumulated Depreciation	95	190	284	379	474	569	663	758	853	948	1 042	1 137	1 232	1 327	1 421	1 516	1 611	1 706	1 800	1 895	1 990	2 085	2 179	2 274	2 369	2 464	2 558	2 653	2 748	2 843
11 Net Plant	3 695	3 601	3 506	3 411	3 316	3 222	3 127	3 032	2 937	2 843	2 748	2 653	2 558	2 464	2 369	2 274	2 179	2 085	1 990	1 895	1 800	1 706	1 611	1 516	1 421	1 327	1 232	1 137	1 042	948
12 Total Assets	3 695	3 601	3 506	3 411	3 316	3 222	3 127	3 032	2 937	2 843	2 748	2 653	2 558	2 464	2 369	2 274	2 179	2 085	1 990	1 895	1 800	1 706	1 611	1 516	1 421	1 327	1 232	1 137	1 042	948
Liabilities and Equity																														
13 Common Equity	1 841	1 770	1 701	1 635	1 571	1 509	1 450	1 392	1 335	1 277	1 220	1 162	1 105	1 048	990	933	875	818	760	703	663	628	594	559	524	490	455	421	386	352
14 Long Term Debt	1 841	1 770	1 701	1 635	1 571	1 509	1 450	1 392	1 335	1 277	1 220	1 162	1 105	1 048	990	933	875	818	760	703	663	628	594	559	524	490	455	421	386	352
15 Deferred Taxes	13	61	104	141	174	203	227	248	268	288	308	328	348	368	389	409	429	449	469	489	475	449	424	398	372	347	321	296	270	244
16 Total Liabilities and Equity	3 695	3 601	3 506	3 411	3 316	3 222	3 127	3 032	2 937	2 843	2 748	2 653	2 558	2 464	2 369	2 274	2 179	2 085	1 990	1 895	1 800	1 706	1 611	1 516	1 421	1 327	1 232	1 137	1 042	948

Cash Flow Statement	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
Operating Activities																														
1 Net Income	100	104	107	111	114	117	119	122	125	128	131	134	136	139	142	145	148	151	153	156	159	161	163	165	167	170	172	174	176	178
2 Depreciation	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
3 Deferred Taxes	13	48	43	38	33	29	24	21	20	20	20	20	20	20	20	20	20	20	20	20	(14)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)
4 Cash Provided by Operating Activities	208	247	245	243	241	240	239	238	240	243	246	248	251	254	257	260	263	265	268	271	239	230	232	234	237	239	241	243	245	247
Investing Activities																														
5 Project	(3 790)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Cash Used in Investing Activities	(3 790)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financing Activities																														
7 Common Stock Issued	1 895	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Long Term Debt Issued	1 895	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Long Term Debt Retired	(54)	(72)	(69)	(66)	(64)	(62)	(60)	(58)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(40)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
10 Common Stock Dividends	(154)	(176)	(176)	(177)	(177)	(178)	(179)	(180)	(183)	(185)	(188)	(191)	(194)	(197)	(200)	(202)	(205)	(208)	(211)	(214)	(199)	(196)	(198)	(200)	(202)	(204)	(206)	(208)	(210)	(213)
11 Cash Provided by Financing Activities	3.582	(247)	(245)	(243)	(241)	(240)	(239)	(238)	(240)	(243)	(246)	(248)	(251)	(254)	(257)	(260)	(263)	(265)	(268)	(271)	(239)	(230)	(232)	(234)	(237)	(239)	(241)	(243)	(245)	(247)
12 Net Cash Flow	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		3.790	Input Investment calibrate at 6.259
13 IRR	20 year	4.38%	iterative or goal seek
14 IRR	25 year	5.57%	
15 IRR	**30 year**	6.25%	

IRR Calculation																															
IRR Calculation	($3 790)	267	303	299	295	291	288	285	282	283	284	285	286	287	288	289	290	291	292	293	294	261	250	251	252	253	254	256	257	258	259
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1 Revenue		462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462	462
2 Operations & Maintenance		(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
3 Franchise Tax	2.74%	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
4 Property Tax	1.50%	(57)	(55)	(54)	(53)	(51)	(50)	(48)	(47)	(45)	(44)	(43)	(41)	(40)	(38)	(37)	(36)	(34)	(33)	(31)	(30)	(28)	(27)	(26)	(24)	(23)	(21)	(20)	(18)	(17)	(16)
5 Net Before Taxes		313	315	316	317	319	320	322	323	324	326	327	329	330	332	333	334	336	337	339	340	342	343	344	346	347	349	350	351	353	354
6 Income Tax	27.00%	85	85	85	86	86	86	87	87	88	88	88	89	89	90	90	90	91	91	91	92	92	93	93	93	94	94	95	95	95	96
7 Net After Tax		229	230	231	232	233	234	235	236	237	238	239	240	241	242	243	244	245	246	247	248	249	250	251	252	253	254	256	257	258	259
8 Tax Benefit on Interest																															
9 Tax Benefit on Investment		38	74	68	63	58	54	50	46	46	46	46	46	46	46	46	46	46	46	46	46	11	0	0	0	0	0	0	0	0	0
10 Total Operating Cash (ROR Analysis)		267	303	299	295	291	288	285	282	283	284	285	286	287	288	289	290	291	292	293	294	261	250	251	252	253	254	256	257	258	259

Plant Additions	Rate	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1 Plant		3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790	3 790
2 Depreciation	2.50%	(95)	(190)	(284)	(379)	(474)	(569)	(663)	(758)	(853)	(948)	(1 042)	(1 137)	(1 232)	(1 327)	(1 421)	(1 516)	(1 611)	(1 706)	(1 800)	(1 895)	(1 990)	(2 085)	(2 179)	(2 274)	(2 369)	(2 464)	(2 558)	(2 653)	(2 748)	(2 843)
3 Net Plant		3 695	3 601	3 506	3 411	3 316	3 222	3 127	3 032	2 937	2 843	2 748	2 653	2 558	2 464	2 369	2 274	2 179	2 085	1 990	1 895	1 800	1 706	1 611	1 516	1 421	1 327	1 232	1 137	1 042	948
4 Deferred Taxes		13	61	104	141	174	203	227	248	268	288	308	328	348	368	389	409	429	449	469	489	475	449	424	398	372	347	321	296	270	244
5 Net Rate Base		3 682	3 539	3 402	3 270	3 142	3 019	2 899	2 784	2 669	2 554	2 440	2 325	2 210	2 095	1 980	1 865	1 751	1 636	1 521	1 406	1 326	1 256	1 187	1 118	1 049	980	911	841	772	703
6 Average Rate Base		3 736	3 611	3 471	3 336	3 206	3 080	2 959	2 842	2 727	2 612	2 497	2 382	2 267	2 152	2 038	1 923	1 808	1 693	1 578	1 464	1 366	1 291	1 222	1 153	1 083	1 014	945	876	807	738
DEBT	Rate																														
7 New Debt		1 895	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Beginning Debt		0	1 841	1 770	1 701	1 635	1 571	1 509	1 450	1 392	1 335	1 277	1 220	1 162	1 105	1 048	990	933	875	818	760	703	663	628	594	559	524	490	455	421	386
9 Principal Payment		(54)	(72)	(69)	(66)	(64)	(62)	(60)	(58)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(40)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
10 Ending Debt		1 841	1 770	1 701	1 635	1 571	1 509	1 450	1 392	1 335	1 277	1 220	1 162	1 105	1 048	990	933	875	818	760	703	663	628	594	559	524	490	455	421	386	352
11 Total Payment		(27)	6	5	5	5	4	4	3	1	(2)	(4)	(7)	(9)	(11)	(14)	(16)	(19)	(21)	(24)	(26)	(11)	(7)	(8)	(10)	(11)	(13)	(14)	(16)	(17)	(19)
12 Interest	4.271%	81	77	74	71	68	66	63	61	58	56	53	51	48	46	44	41	39	36	34	31	29	28	26	25	23	22	20	19	17	16
EQUITY																															
13 Paid in		1 895	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 Beginning Equity		0	1 841	1 770	1 701	1 635	1 571	1 509	1 450	1 392	1 335	1 277	1 220	1 162	1 105	1 048	990	933	875	818	760	703	663	628	594	559	524	490	455	421	386
15 Excess Dividend	(Net Inc)	(154)	(176)	(176)	(177)	(177)	(178)	(179)	(180)	(183)	(185)	(188)	(191)	(194)	(197)	(200)	(202)	(205)	(208)	(211)	(214)	(199)	(196)	(198)	(200)	(202)	(204)	(206)	(208)	(210)	(213)
16 Net Income		100	104	107	111	114	117	119	122	125	128	131	134	136	139	142	145	148	151	153	156	159	161	163	165	167	170	172	174	176	178
17 Ending Equity		1 841	1 770	1 701	1 635	1 571	1 509	1 450	1 392	1 335	1 277	1 220	1 162	1 105	1 048	990	933	875	818	760	703	663	628	594	559	524	490	455	421	386	352
18 Average Equity		1 868	1 805	1 735	1 668	1 603	1 540	1 480	1 421	1 363	1 306	1 248	1 191	1 134	1 076	1 019	961	904	847	789	732	683	645	611	576	542	507	473	438	403	369

Tax Depreciation		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Total
1 Tax Depreciation Rate		3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	1.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	98.88%
2 Plant Additions		3 790																														
3 Total Tax Depreciation		142	274	253	234	217	200	185	171	169	169	169	169	169	169	169	169	169	169	169	169	42	0	0	0	0	0	0	0	0	0	0
4 Tax Benefit @	27.00%	38	74	68	63	58	54	50	46	46	46	46	46	46	46	46	46	46	46	46	46	11	0	0	0	0	0	0	0	0	0	0
Book Depreciation																																
5 Book Depreciation Rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	
6 Plant Additions		3 790																														
7 Book Depreciation		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	2 843
8 Total Book Depreciation		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	2 843
9 Total Tax Depreciation		142	274	253	234	217	200	185	171	169	169	169	169	169	169	169	169	169	169	169	169	42	0	0	0	0	0	0	0	0	0	0
10 Difference		47	179	158	139	122	106	91	77	74	74	74	74	74	74	74	74	74	74	74	74	(52)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(95)	(2 843)
11 Deferred Taxes	27.00%	13	48	43	38	33	29	24	21	20	20	20	20	20	20	20	20	20	20	20	20	(14)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	244
20 year MACRS		3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

	Capital Structure	Cost Rate	Cost	After-tax Cost
Debt	50.00%	4.271%	2.136%	1.559%
Equity	50.00%	9.400%	4.700%	4.700%
	100.00%		6.836%	6.259%

Construction Costs 3 790

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Reply Testimony of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1900

June 6, 2022

EXHIBIT 1900 - REPLY TESTIMONY - CUSTOMER COMMUNICATIONS

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Are you the same Cory Beck who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/900, Beck.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to the Opening Testimony of Greer Ryan, of Climate Solutions (providing testimony on behalf of the Coalition[1]) concerning NW Natural's customer communications (or advertising)[2] expenses for the Test Year (November 1, 2022 to October 31, 2023). As it relates to Coalition witness Ms. Ryan's Opening Testimony, I also describe the adjustment for advertising expense and customer survey expense included in the Multi-Party Stipulation Regarding Revenue Requirement, Rate Spread, and Certain Other Issues ("Stipulation") between NW Natural, Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), the Alliance of Western Energy Consumers ("AWEC"), and the Small Business Utility Advocates ("SBUA") (collectively, "Stipulating Parties") that was filed on May 31, 2022.

[1] The Coalition includes the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and Sierra Club.

[2] NW Natural uses the term "customer communications," while other parties use the term "advertising." NW Natural understands these terms to be referring to the same category of expense. These terms are used interchangeably throughout this testimony.

Q. Please summarize your testimony.

A. In my testimony, I:

- Provide relevant background regarding Category A, B, and C customer communications expense;
- Respond to the Coalition's proposed adjustments to Category A customer communications expense;
- Respond to the Coalition's proposed adjustments regarding Category B communications expense;
- Summarize the Coalition's quantifiable adjustments regarding Category A and B advertising expense; and
- Respond to the Coalition regarding the customer survey expense.

Q. Do Staff and CUB also propose adjustments regarding Category A and Category B customer communications and advertising expenses and customer survey expense?

A. Yes, however, Staff and CUB are parties to the Stipulation, and it is my understanding that the Stipulation resolves the adjustments they proposed in their Opening Testimony on these topics.

Q. Do you include any exhibits with your testimony?

A. Yes, I am presenting the following exhibits:

- NW Natural/1901, Beck - Recommended Practice 1162; and
- NW Natural/1902, Beck - Category B – 2021 Safety Implementation Plan.

Q. Are there other NW Natural witnesses who address the Opening Testimony of Greer Ryan?

A. Yes. The Reply Testimony of Kimberly Heiting and Ryan Bracken, NW Natural/1700, Heiting-Bracken, responds to Coalition Witness Ryan's proposals to disallow the recovery of all costs associated with its membership in the American Gas Association and the Northwest Gas Association, and to disallow all of the costs of NW Natural's Government Affairs department. Additionally, Ms. Heiting and Mr. Bracken's testimony addresses Ms. Ryan's comments regarding indoor air quality issues associated with natural gas appliances.

II. BACKGROUND REGARDING CUSTOMER COMMUNICATIONS EXPENSE

Q. What are expenses for Category A communications?

A. Category A expenses are utility service advertising expenses and utility information advertising expenses.[3] Under OAR 860-026-0022(3)(a), expenditures for Category A advertising up to 0.125 percent of gross retail operating revenues are presumed just and reasonable. As I explained in my Direct Testimony, in NW Natural's case, that percentage results in $796,789 for Category A communications based on 2020 revenues, which is equivalent to about $1.17 per customer, or for the Test Year, it would be $1,019,914, or $1.40 per customer.[4]

[3] OAR 860-026-0022(2)(a).

[4] NW Natural/900, Beck/4.

Q. Did NW Natural request more than the amount of Category A expense presumed reasonable for the Test Year?

A. Yes. As I explained in my Direct Testimony, the threshold in OAR 860-026-0022(4) sets an amount that is presumed reasonable, but allows for more to be recovered as long as support is provided, and the Commission approves it.[5] The Company's proposed Category A request for cost recovery amounts to approximately $2.60 per customer, which is more in line with its peer utilities in the Portland area, PacifiCorp and Portland General Electric. I provided a detailed explanation that the additional amount requested was justified because: (1) media consumption habits have evolved such that NW Natural uses a diversified mix of media channels to communicate with customers; (2) NW Natural's service territory spans a broad region, including two distinct media markets (Portland and Eugene); (3) in addition to providing information about payment options and programs, online customer service, billing, payment, and rate information, NW Natural has continued to invest in its educational and informational communications about climate-related issues, including the Company's actions to acquire renewable natural gas ("RNG") under Senate Bill ("SB") 98 legislation. With target spending at approximately $2.60 per customer, the Company ultimately requested $1,847,073 for Category A customer communications expense.

[5] NW Natural/900, Beck/6.

Q. What are Category B customer communications?

A. Category B communications are safety-related communications, and include legally mandated messages intended to ensure that NW Natural's customers, contractors, public officials, emergency officials and the general public within the NW Natural service territory know how to use natural gas safely, are prepared in the event of an earthquake, know how to recognize, react, and respond to a potential leak or safety issue related to natural gas, and know how to prevent damages to underground utility pipelines. In accordance with OAR 860-026-0022(3)(b), Category B communications are presumed to be just and reasonable for ratemaking purposes. NW Natural requested $1,080,000 for the Category B customer communications for the Test Year.

Q. What are Category C customer communications?

A. Category C communications are designed to aid in the retention of customers and attract new customers by promoting the cost and performance benefits of natural gas and a variety of natural gas products. In accordance with OAR 860-026-0022(3)(c), Category C expense may be included in rates, but the utility will carry the burden of showing the reasonableness of the expenses. As I explained in my Direct Testimony, NW Natural budgeted approximately $600,000 for Category C expense in the Test Year and did not request recovery for any Category C expense in this case.

Q. Does the Stipulation address customer communications expense?

A. Yes. As part of the Stipulation, NW Natural agreed to reduce its customer communications (or advertising)[6] expense by $1.0 million.[7] Thus, while NW Natural's initial request for Category A and Category B customer communications expense totaled approximately $2.970 million, the agreement in the Stipulation would reduce this expense to a total of $1.970 million.

Q. Does your Reply Testimony describe and support the agreement in the Stipulation regarding advertising?

A. My understanding is that the Stipulating Parties will file Joint Testimony supporting the Stipulation in early June 2022. My Reply Testimony is primarily intended to respond to the Coalition's Opening Testimony. While my Reply Testimony explains why the Coalition's adjustments should be rejected, it is important to note at the outset that the Company's request for customer communications expense is significantly reduced based on the adjustment for advertising included in the Stipulation. Thus, while the Company urges that the Coalition's adjustment should be rejected, the Company asks that the Commission approve the amount of advertising expense reflected in the Stipulation rather than the amount included in the Company's initial request.

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6 In the Stipulation, customer communications expense is referred to as "advertising."

7 Stipulation at 5 (May 31, 2022).

III. CATEGORY A CUSTOMER COMMUNICATIONS EXPENSE

Q. What is the Coalition's recommendation regarding Category A customer communications expense?

A. The Coalition argues that the Company's entire Category A budget should be disallowed, because the Company's advertising primarily seeks to improve the Company's image and promote the consumption of natural gas, which would be considered Category C advertising.[8]

Q. What are the major topics covered in the Coalition's testimony regarding advertising?

A. The Coalition specifically addresses four advertising-related topics in its testimony: (1) natural gas safety education materials provided to schools; (2) indoor air quality related advertising; (3) RNG advertising; and (4) advertising that promotes maintaining natural gas utility service, compares natural gas appliances with electric appliances, or promotes fuel switching.

Q. Are all of these topics relevant to Category A advertising?

A. No. The natural gas safety education materials are Category B communications expense and are discussed below in Section IV. In this Section III of my testimony, I first address the Coalition's testimony regarding RNG-related communications, then indoor air quality, and finally promotional/fuel switching advertising.

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[8] Coalition/400, Ryan/11-12.

A. RNG Advertising

Q. Why is NW Natural communicating with its customers regarding its investment in RNG?

A. As I explained in my Direct Testimony, NW Natural understands that its customers are concerned about climate change, and the Company believes there is a need to inform and educate customers about the Company's energy supply strategy, emissions reduction goals, opportunities for emissions reductions, and the benefits of RNG. NW Natural communicates these messages through its "Less We Can" initiative, as well as through other communications campaigns.

Q. Please explain why NW Natural considers the Less We Can / RNG campaign as appropriate for cost recovery as a Category A expense.

A. Under OAR 860-026-0022(2)(a), "Category A" advertising expenses include energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses. In turn, "utility information advertising expenses," are defined as:

> advertising expenses, the primary purpose of which is to increase customer understanding of utility systems and the function of those systems, and to discuss generation and transmission methods, utility expenses, rate structures, rate increases, load forecasting, environmental considerations, and other contemporary items of customer interest[.][9]

[9] OAR 860-026-0022(1)(g).

The development of RNG, carbon savings associated with RNG and programs for customers to engage are new to the natural gas industry and are complicated issues that require information and education to be successful. The Less We Can campaign provides information regarding conservation and energy efficiency, education about opportunities for offsetting customer emissions, and RNG development and technology advancements that can help lower emissions. Through its RNG campaign, the Company is providing customers with valuable information that addresses "environmental considerations" and "contemporary items of customer concern," which are squarely within the definition of Category A communications.

Q. What are the Coalition's criticisms of the Company's RNG-related customer communications?

A. The Coalition claims that the Company's RNG-related customer communications are primarily promotional in nature, and that it is misleading because it implies more RNG is on the Company's system than is currently included in the fuel mix, and because it implies that the energy content of the gas from the Lexington RNG Project (located in Nebraska) will be used in Oregon. I will address these criticisms in greater detail in turn.

Q. How do you respond to the Coalition's claims that the Company's RNG-related advertising is promotional in nature because it is intended to promote the Company's brand rather than inform customers?

A. I disagree with the assertion that the RNG advertising is promotional in nature. Through the Company's market research, the Company understands that its customers are concerned about climate change,[10] prompting the Company to explain more about how the Company is responding to new policies aimed at reducing emissions, such as SB 98. NW Natural has been working hard to add RNG to its system and is eager to share its plans with its customers, and believes it is entirely appropriate to do so as climate change and RNG are both "environmental considerations" and "contemporary items of customer concern," enumerated in the rule. It is clear from the advertising examples (specifically shown in Figures 1 through 3 in my Reply Testimony, below), that the purpose of the message is to educate about what RNG is, how RNG is created, and NW Natural's plans for integrating RNG into the resource mix. Additionally, the fact that the Company's messaging is resonating with our customers does not mean that it is promotional in nature, but rather indicates that the Company's approach to messaging and advertising is effective.

Q. By contrast, what is promotional advertising?

A. As I explained above, promotional advertising is designed to aid in the retention of customers and attract new customers by promoting the cost and performance benefits of natural gas and a variety of natural gas products. NW Natural specifically excluded promotional advertising—or Category C communications—from its request for cost recovery.

[10] NW Natural/904, Beck; NW Natural/905, Beck.

Q. The Coalition also claimed that the RNG-related advertising was misleading because the Company implied that there is already RNG on the Company's system, when in fact NW Natural is just beginning to add RNG.[11] How do you respond?

A. I disagree with the Coalition's assertion that the advertising is misleading. While RNG currently makes up only a relatively small portion of the Company's resource mix, the Company expects to continue expanding to meet its target of 5 percent RNG by 2025 and 10 percent over the next several years.[12] NW Natural is eager to share its plans with its customers, and while the Coalition apparently takes issue with the phrasing of certain messages in the RNG communications, the ads are not misleading customers.

Q. What are some of the specific messages that the Coalition alleges are misleading?

A. The Coalition lists the following messages, and claims that they are misleading because they imply that the Company is providing RNG to its commercial and residential customers:

- "We received the green light for renewable natural gas, and can now bring renewable energy directly to our customers. Rulemaking for Senate Bill 98 is complete, giving us a clear path to acquire renewable natural gas, and forging the way for this newest renewable resource to be an increasing part of the state's energy supply. Learn more about renewable natural gas—a zero-carbon resource produced from local organic materials—at Less We Can DOT com."

[11] Coalition/400, Ryan/26-27.

[12] NW Natural/2100, Chittum.

- "Our facility in Mist, Oregon, provides 20 billion cubic feet of underground storage capacity. That translates into 6 million megawatt hours of renewable storage capability or the equivalent of a $2 trillion dollar battery. This existing storage is already in place, can deliver on-demand, and is primed to store renewable molecules."
- "Renewable natural gas is made from organic materials like wood, food and even human waste, and can be delivered through our existing pipeline to your home or business."
- "We are partnering with BioCarbon, a developer and operator of sustainable infrastructure projects, to convert methane from some Tyson Foods facilities into renewable natural gas to heat homes and businesses. Once fully operational, this project is expected to generate enough renewable natural gas each year to heat 18,000 homes we serve in Oregon."
- "New laws in Oregon and Washington will enable NW Natural to begin delivering renewable natural gas to our customers in 2020. We're excited to join these innovative utilities in helping close the loop on waste."
- "NW Natural is investing in renewable natural gas projects to acquire renewable natural gas for customers. With the first two agreements in place, we can purchase or develop enough renewable natural gas to heat about 36,000 homes. And this is just the beginning. See details at nwnatural.com/RNG."[13]

Q. Are all of the statements listed above true?

A. Yes. Notably, the Coalition did not claim that any of these statements are false, or provide evidence refuting any of these statements. Instead, it asserts that the statements are misleading because they imply that there is more RNG on NW Natural's system than there currently is today, and it suggests that NW Natural should be disclosing that the Lexington Project will be used to purchase renewable thermal credits rather than supplying the energy content of that gas directly to NW Natural's customers.

[13] Coalition/400, Ryan/24-26.

Q. How do you respond to the Coalition's assertions that the Company's messages are misleading?

A. I strongly disagree. First, as discussed above, all of the statements in the RNG messaging are true. NW Natural is communicating with its customers about its plans for the future and the capabilities of the current system to adapt for the increasing use of RNG. To communicate this message effectively, NW Natural provides the information in a simplified manner with illustrative examples that are likely to be understood by a broad audience. As such, the communications messaging will not contain the same level of detail or granularity as the compliance for a regulatory proceeding or compliance filing. Links to additional information and more details are included on most advertising.

Q. How do you respond to the Coalition's complaint that the RNG advertising is misleading because NW Natural does not disclose that residential and commercial customers do not currently receive RNG?

A. The Coalition specifically references Figure 1, below, for this assertion.

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Figure 1. RNG Digital Communications.

However, the communications shown above do not represent that any amount of RNG is being provided to customers. Instead, these communications are intended to raise awareness about RNG and educate customers regarding the Company's plans to add more RNG to its resource mix. Importantly, the communications also redirect the view to the Company's "Less We Can" website, which provides more detailed information about RNG.

Q. How do you respond to the Coalition's assertion that NW Natural should be disclosing that the Lexington Project will be used to purchase renewable thermal credits rather than supplying the energy content of the gas directly to NW Natural's customers?

A. I believe the Coalition's concern is misplaced. As discussed above, NW Natural's advertising describes NW Natural's plans for the future and provides an illustration of the amount of RNG that NW Natural is procuring. As further discussed in the

Reply Testimony of Anna Chittum (NW Natural/2100, Chittum) federal and state programs, including SB 98, the Climate Protection Program (CPP), and the Oregon Clean Fuels Program, rely on NW Natural retaining the environmental attributes of RNG being delivered to satisfy program requirements.[14]

Q. The Coalition also asserts that NW Natural's advertising is misleading when it says that "On the coldest winter days NW Natural provides 90 percent of the energy our residential space and water heating customers need. Yet use of the gas accounts for only 6% of Oregon's greenhouse gas emissions." The Coalition asserts this statement implies that NW Natural is providing 90 percent of residential home heating in wintertime, which is incorrect, because the statement only refers to customers who use natural gas for home heating.[15] How do you respond?

A. I disagree that the communication is misleading, and instead believe it provides customers with useful information. The full message is provided below, in Figure 2:

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[14] NW Natural/2100, Chittum/12-15.

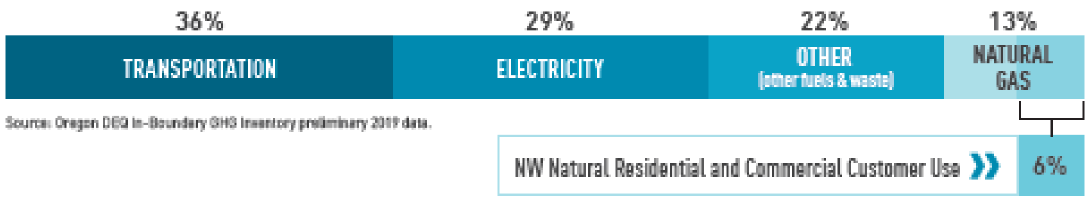
[15] Coalition/400, Ryan/31.

Figure 2. Vision 2050: Destination Zero Report (Excerpt 1)

Innovating Toward Carbon Neutrality

On the coldest winter days NW Natural provides 90% of the energy our residential space and water heating customers need. Yet the use of the gas we purchase for customers accounts for only 6% of Oregon greenhouse gas emissions.[1] We're working to reduce those numbers even further.

OREGON GREENHOUSE GAS EMISSIONS BY SECTOR



Carbon neutrality means having a balance between emitting carbon and absorbing carbon from the atmosphere. In the Destination Zero report, we analyze three different scenarios using various combinations of decarbonization measures (energy efficiency, renewable energy, carbon offsets and carbon capture, utilization and sequestration) that allow us to build upon our existing efforts and realize our vision for a carbon neutral gas utility.

Central to all scenarios is the replacement of conventional natural gas with carbon neutral alternatives like renewable natural gas and clean hydrogen over time.

Renewable Natural Gas

Renewable natural gas is produced from organic materials like food, agricultural and forestry waste, landfills and wastewater. With a similar climate benefit to wind and solar, RNG turns the problem of waste into a powerful climate solution using our pipeline network already in place. Just as the electric grid's transmission lines can deliver electricity made from natural gas, coal, hydro, wind or solar, our pipelines can deliver natural gas from conventional or renewable sources.

Early Progress on RNG

Within just one year of ground-breaking Oregon legislative rules being in place, NW Natural has signed agreements to purchase and develop 3% of our supply as RNG—enough renewable gas to heat the equivalent of all the homes we serve in Eugene and Corvallis. With wind and solar accounting for 11% of U.S. electric generation after decades of development, we are proud of this early progress.[2]

2 https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

1 Our Clark, Klickitat and Skamania County customers' natural gas use accounts for half a percent (0.5%) of greenhouse gas emissions in Washington state: Washington Department of Ecology 2012 GHG Inventory

The point of the message is that NW Natural meets most of the overall energy needs of its residential and commercial customers on the coldest days in the winter, and those customers' greenhouse gas emissions from natural gas only make up 6 percent of the total in the State—and the Company is seeking to reduce that amount through its emissions reductions goals.

Q. The Coalition also asserts that it is misleading for NW Natural to tout RNG as vehicle fuel because it is not relevant to gas utility service.[16] How do you respond?

A. I disagree with the Coalition's assertion. The piece referenced is an article (shown below in Figure 3) in the NW Natural customer newsletter, congratulating a NW Natural Customer for adopting renewable natural gas and reducing greenhouse gas emissions by more than 40 percent.

Figure 3. Cherriots Fleet

Less We Can: Cherriots is now the state's cleanest public transit fleet, thanks to renewable natural gas

LESS WE CAN

Longtime NW Natural customer and community partner Cherriots public transportation in Salem-Keizer is now the state's cleanest public transit fleet, powering over half of its fleet with renewable natural gas.

By using renewable natural gas, Cherriots expects to reduce harmful smog-forming tailpipe emissions by more than 90% and greenhouse gas emissions by more than 40%.

"Clean public transit is key as we move toward a more healthy, sustainable and equitable Oregon. Transportation is the single largest source of greenhouse gas emissions in Oregon, as well as other harmful pollutants that put vulnerable communities at risk. We need to rapidly decarbonize the transportation sector, including medium and heavy-duty vehicles like trucks and buses. I commend Cherriots for leading the way with cleaner, renewable natural gas buses," said Oregon Governor Kate Brown.

"This is a perfect example of the creative thinking and problem solving we need in our community," said Salem Mayor Chuck Bennett.

By using renewable natural gas, Cherriots expects to reduce harmful smog-forming tailpipe emissions by more than 90% and greenhouse gas emissions by more than 40%.

The cost savings from using renewable natural gas will allow Cherriots to expand its bus service and help maintain affordable fare prices.

What is renewable natural gas?

Renewable natural gas is a zero-carbon resource produced from local, organic materials like food, agricultural and forestry waste, wastewater or landfills. As these materials decompose, they produce methane. That methane can be captured, conditioned to pipeline quality and delivered in the existing pipeline system to homes and businesses where it can be used in existing natural gas appliances, equipment and vehicles. This process closes the loop on waste and provides a renewable energy option for the natural gas system, in the same way that wind and solar are used to generate renewable electricity.

Learn more about renewable natural gas and how we innovate sustainable ways to meet the demands of the region's growing population at nwnatural.com.

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[16] Coalition/400, Ryan/32.

NW Natural is trying to accomplish similar goals for all customers through the implementation of RNG, making the piece relevant to natural gas utility service. The article illustrates that point by showcasing the achievements of a valued customer and that by incorporating RNG into the energy mix, verifiable reductions in greenhouse gas emissions can be achieved. Further, NW Natural agrees with the quotes provided in the article by Oregon Governor Kate Brown, "I commend Cherriots for leading the way with cleaner, renewable natural gas busses," and by Salem Mayor Chuck Bennett, "This is a perfect example of the creative thinking and problem solving we need in our community."

B. Indoor Air Quality Advertising

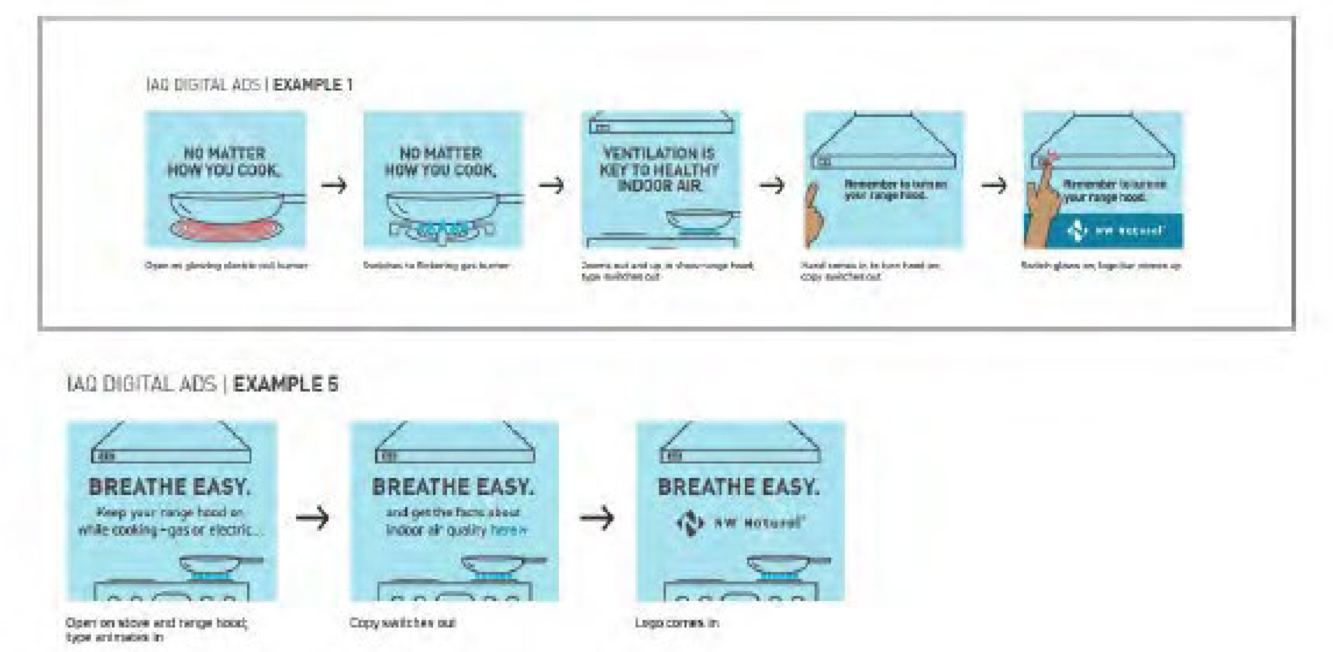
Q. What concerns does the Coalition raise regarding indoor air quality?

A. The Coalition asserts that NW Natural is providing misleading advertising regarding gas stoves, and describes two advertisements that encourage the use of proper ventilation when cooking with gas or electric appliances.[17] The Coalition further asserts that NW Natural failed to provide information regarding NOx, carbon monoxide, and formaldehyde that gas stoves emit, which can contribute to respiratory illness.[18] For convenience, the images are copied below in Figure 4.

[17] Coalition/400, Ryan/21.

[18] Coalition/400, Ryan 22.

Figure 4. Indoor Air Quality Digital



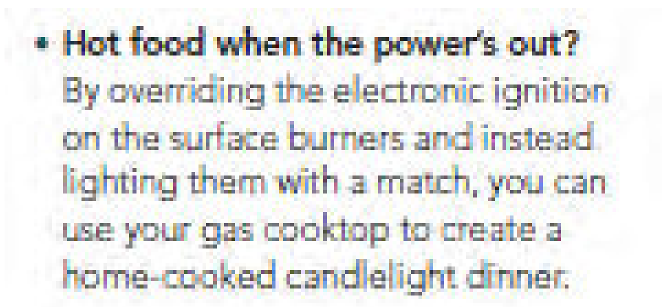
Q. How do you respond?

A. First, to clarify, only the first image (i.e., "Example 1") was published. The second image (i.e., "Example 5") is a concept that was inadvertently included with the Company's response to CUB Data Request No. 4, as this image was not used in advertising. In any event, the purpose of the communication is to educate customers regarding the use of proper ventilation when cooking, which is necessary when cooking on any appliance—whether gas or electric. This advertising is appropriately considered Category A because it addresses a contemporary item of customer interest – cooking. Finally, the Coalition's assertions regarding natural gas stoves contributing to respiratory illness are addressed in the Reply Testimony of Kimberly Heiting and Ryan Bracken.

Q. The Coalition also asserts that NW Natural is promoting dangerous behaviors such as encouraging customers to use gas cooktops for a home-cooked candlelight dinner, implying that customers should use the cooktop as a lighting source.[19] How do you respond?

A. The Coalition is taking this customer communication entirely out of context. In the March 2021 bill insert, the Company provided information regarding a customer's ability to use their gas cooktop even during a power outage, shown below in Figure 5.[20] This is useful information for customers, and clearly does not imply that gas cooktops should be used for lighting.[21] The reference to candlelight in the message was included because the message describes the use of a cooktop during a power outage, and presumably customers may be using candles for lighting during a power outage.

Figure 5. Power Outage Information



- **Hot food when the power's out?**
  By overriding the electronic ignition on the surface burners and instead lighting them with a match, you can use your gas cooktop to create a home-cooked candlelight dinner.

[19] Coalition/400, Ryan/23.

[20] Coalition/405, Ryan/49.

[21] Coalition/400, Ryan/23.

Q. The Coalition also asserts that NW Natural is promoting dangerous behaviors such as encouraging customers to use Wi-Fi technology to start their oven or monitor a meal while not home.[22] How do you respond?

A. I disagree with the Coalition's implication that NW Natural is encouraging customers to use their ovens while they are not home.[23] The communication with customers (shown below in Figure 6) simply describes the availability of the Wi-Fi technology, and even refers to a customer's home office, which presumably would be in another room of the home. While the communication also refers to a walking route, NW Natural does not believe it is unsafe or unusual for a customer to take a short walk while the oven is on and believes that customers will exercise good judgment in doing so.

Figure 6. Wi-Fi Controls

> • **For the multitasker.** Wi-Fi technology lets you preheat your oven or monitor your meal's progress from your home office or walking route.

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[22] Coalition/400, Ryan/23.

[23] Coalition/405, Ryan/49.

C. Cooking with Gas Ads / Promotional Advertising

Q. Ms. Ryan references the "Cooking with Gas" Campaign and asserts that it is promotional in nature.[24] Ms. Ryan similarly asserts that the Company's communications describing customers' preferences, comparing electric and natural gas appliances, and promoting fuel switching are promotional advertising.[25] How do you respond?

A. The campaign and communications referenced by Ms. Ryan on pages 34-38 of her Opening Testimony are, in fact, Category C expense for which the Company is not requesting recovery in this rate case. The Company inadvertently provided these communications in response to a request for all Category A advertising in CUB DR 4, however, I have confirmed that all but one of these communications referenced on pages 34-38 of Ms. Ryan's Opening Testimony in fact were booked to Category C.

Q. Was one of the Category C advertisements inadvertently booked to Category A?

A. Yes. In preparing this Reply Testimony, NW Natural discovered that for the Base Year, $124,221 in Oregon-allocated costs were charged to Category A that should have been charged to Category C for production of: NW Natural_ ConsumerInformation_Performance_TV.mp4.

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[24] Coalition/400, Ryan/32.

[25] Coalition/400, Ryan/33-38.

Q. Is this a correction to the Base Year or the Test Year?

A. This correction is to the Base Year and does not change the Category A expense included in the Test Year, which is based on a target of $2.60 per customer.

Q. On page 33 of Ms. Ryan's Opening Testimony, she also refers to a message that was included in the Company's customer newsletter and asserts that it is promotional in nature. How do you respond?

A. The message that Ms. Ryan refers to is included below in Figure 7, and I agree that it is promotional in nature. The message includes information of contemporary interest to customers regarding the potential impacts of natural gas appliances on home prices, but also includes a link to the Company's website regarding natural gas preference. Accordingly, this particular message would more appropriately be recorded to Category C.

Figure 7. Excerpt from March 2021 Comfort Zone Newsletter

Q. How was the message shown in Figure 7 distributed to customers?

A. This message was included in the Company's March 2021 "Comfort Zone" customer newsletter, with a variety of other messages, including both utility information and safety information. The Company's "Comfort Zone" newsletters are typically published five to six times per year, and in 2021 the Company published five such newsletters. Of the "Comfort Zone" newsletters published in 2021, the March 2021 edition is the only newsletter that included a link to the Company's website discussing customer preference information.

Q. What is the cost associated with the message shown in Figure 7?

A. The total Oregon allocated cost of the March 2021 newsletter was $18,145, and of that amount I would estimate that approximately $3,000 is attributable to the message shown in Figure 7.

Q. Is the Company planning to update its process for coding costs associated with the "Comfort Zone" newsletters in the future?

A. Yes. Typically, the "Comfort Zone" newsletters are billed to Category A because the primary purpose of the newsletter is to provide utility and billing information to the customers, along with other messages that may be of interest to the customer. Going forward, my department will more carefully review the content of the Customer Zone newsletters to ensure that the messages are being recorded to the appropriate cost center (Category A, Category B, Category C).

IV. CATEGORY B CUSTOMER COMMUNICATIONS EXPENSE

Q. What is the Coalition's position on Category B expense?

A. The Coalition is proposing to disallow all Category B expense.[26] The Coalition asserts that "a few advertisements funded by NW Natural legitimately relate to safety hazards," but claims that because they are published alongside promotional advertising, the Commission should disallow recovery for all safety related advertising expense.[27] The Coalition particularly takes issue with the educational materials for school children addressing gas safety, which the Coalition alleges is "gas propaganda."[28]

Q. Did you describe the safety materials for school children in your Direct Testimony?

A. Yes, I briefly mentioned in my Direct Testimony that NW Natural has a contract with Culver Company ("Culver") to provide educational materials for contractors, first responders, and a school program to raise public awareness regarding natural gas safety.[29]

Q. Is the school safety materials program from Culver a relatively new addition?

A. Yes. NW Natural has had a contract with Culver to provide educational materials for approximately the last four years, the scope of which the parties expanded in 2020 for Culver to also include the school materials.

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[26] Coalition/400, Ryan/4.

[27] Coalition/400, Ryan/4.

[28] Coalition/400, Ryan/4.

[29] NW Natural/900, Beck/19.

Q. Prior to the Culver program, did NW Natural use a different contractor for a school program?

A. Yes. NW Natural used another vendor, Enterprise for Education. NW Natural changed to Culver because the Culver School Safety Program is more comprehensive and has a broader range of offerings.

Q. The Coalition states that NW Natural has not identified any laws requiring advertising campaigns aimed at children.[30] Why did NW Natural expand its agreement with Culver to include the gas safety materials for educators?

A. In accordance with U.S. Code of Federal Regulations Title 49 Parts 192.616 and 195.440 and standards administered by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, NW Natural has a federally mandated obligation to comply with the Public Safety Awareness Plans described in Recommended Practice API 1162 ("RP-1162"). These regulations require pipeline operators to establish continuing education programs to enable the public, appropriate government organizations, and persons engaged in excavation-related activities to recognize a pipeline emergency and to report it to the operator and/or the police, or other appropriate public officials.

As described in RP-1162, the target audiences for these messages include: (1) the affected public; (2) emergency officials; (3) local public officials; and (4) excavators. The affected public includes *not only* customers, but also anyone who may come into contact with the natural gas system.

[30] Coalition/400, Ryan/19.

Schools within the NW Natural service territory are part of the affected public stakeholder audience category. RP-1162 recommends the distribution of targeted print materials to this audience. Through on-going discussions with Culver, NW Natural learned about their gas safety materials for educators and students and determined that moving the program for gas safety materials for schools from the prior company could be a more effective way of providing important safety information at an individual level to an at-risk audience category.

Q. Do other utilities also use similar safety-related educational materials for educators and students?

A. Yes, it is relatively common in the industry for utilities to provide safety programs to schools. Based on my review, it appears that the following utilities, including PGE in Portland, are also using educational materials published by Culver:

- Cascade Natural Gas: https://cngc.e-smartkids.com/
- Portland General Electric: https://portland.e-smartkids.com/
- Intermountain Gas Company: https://intgas.e-smartkids.com/
- Michigan Gas Utilities: https://michigangasutilities.e-smartkids.com/
- Southern California Edison: https://sce.e-smartkids.com/
- Los Angeles Department of Water & Power: https://ladwp.e-smartkids.com/
- Xcel Energy: https://xcelenergy.e-smartkids.com/
- Dominion Energy: https://e-smartonline.net/dom/
- PPL: https://ppl.e-smartkids.com/
- Duke Energy: https://e-smartonline.net/duke-energy/

Q. Why is it important to communicate with schools, educators, and students regarding natural gas safety?

A. In addition to the federal requirements discussed above, NW Natural views its safety messages critically important to ensuring the safety of its customers and the general public. Indeed, the importance of communicating gas safety information has been highlighted in fairly recent gas safety incidents. For example, after the gas explosion in East Harlem in 2014, local officials and the utility, Consolidated Edison, were dismayed by the fact that people in the area said they could smell a natural gas leak for a number of days or weeks before the first call was placed to report the incident to the utility.[31]

Q. Please describe the gas safety materials that are provided to schools.

A. The gas safety materials include educational classroom booklets, teachers' lesson planning guide, e-SMARTkids educational website and videos, with targeted content based on grade level. The materials contain information about gas safety and educational background about the history and uses of natural gas. Critically, these materials inform school children about the odorizer, mercaptan, that is added to natural gas, and specifically instructs children that the odorizer smells like rotten eggs, and if they detect that smell, they should leave the area and tell an adult about it.

[31] "Report of Gas Odors Surge After East Harlem Blast," New York Times (May 15, 2014) https://www.nytimes.com/2014/05/16/nyregion/reports-of-gas-odors-surge-after-east-harlem-blast.html

Q. In addition to the safety-related content, why do the materials also contain information about the history of natural gas and its uses?

A. As I explained above, pursuant to 49 CFR 192.616, NW Natural is required to implement RP-1162. In turn, RP-1162 directs owners and operators of natural gas systems to inform the public of the purpose of their gas systems, and that the systems are operated to meet the energy needs of the region, "even though this is not the primary objective of pipeline safety public awareness." The content is designed to comply with these requirements by making audiences aware of (a) the presence of natural gas and natural gas systems and (b) the security and safe operations of these systems; the latter includes providing information concerning the location of gas systems in their areas, steps audience members should take to help prevent gas-related accidents, and steps audiences should take to recognize gas incidents (such as a release) as well as how to safely respond to a gas incident.

Q. The Coalition also claims that gas safety materials address safety only secondarily, and do not fully disclose the risk of harm associated with a gas leak, such as a fire or explosion.[32] How do you respond?

A. As an initial matter, this is not true. The activity booklets disclose the fact that a gas leak can be a fire hazard.[33] Second, the reason the materials include information about natural gas (what it is, how it was created, what is used for) in

[32] Coalition/400, Ryan/18.

[33] Coalition/406, Ryan/33, 71, 72, 80, 88.

the beginning is to set a common baseline of knowledge for the teacher and students. Additionally, to understand natural gas safety, it is important to know what natural gas is – an odorless, colorless, gas.

NW Natural's top priority for public safety is to protect human life. Therefore, our main goal in safety communications to the general public is to provide three key messages as identified in the guidelines: 1) what does natural gas smell like; 2) what do you do if you smell gas; and 3) who do you contact if you smell gas. While there are many other messages, the three key messages above are the most important for the general public, and the top priority to keep people safe. That is also why we only focus on these same three key messages in television advertising for the general public.

Q. The Coalition describes the gas safety materials as propaganda and asserts the primary purpose of the booklets is to promote continued use and consumption of natural gas by influencing public opinion (for example, by associating natural gas with dinosaurs or pizza).[34] How do you respond?

A. I disagree with this characterization of the purpose of the materials. The information presented in the school materials is not being used to promote or publicize a cause or point of view. As I indicated above, the purpose of the materials is to educate about natural gas safety in conformance with federal law and RP-1162. The Culver materials were developed for an age-specific audience

[34] Coalition/400, Ryan/19.

to ensure that the messaging is presented in an accessible and age-appropriate way and to help ensure retention of the information.

Q. How are these gas safety materials distributed to schools?

A. NW Natural's contractor, Culver, maintains a list of the public and private schools in the zip codes in NW Natural's service territory. Culver contacts the schools and makes the gas safety materials available to them free of charge on an opt-in basis.

Q. Does Culver send gas safety educational materials to schools that do not opt in?

A. No, Culver only sends the gas safety educational materials to schools that request them.

Q. What is the cost for the school program relative to NW Natural's budget for Category B communications expense?

A. For the 2020 and 2021 programs, the Oregon allocated average spending on the school safety program is approximately $62,000, or only 8 percent of the total Category B expense for the two years.

Q. If the school program comprises only about 8 percent of the expense for Category B, what other programs are included in Category B?

A. As shown in NW Natural/1902, NW Natural's Category B communications expenses include many elements and cover many safety messages such as "Smell. Go. Let us know," "811 – Call Before You Dig", earthquake safety, carbon monoxide safety, equipment inspection, kitchen safety, as well as pipeline location and safety awareness and other targeted messages. NW Natural communicates these safety messages with the affected public, customers, contractors and emergency response providers through a variety of means specific to the audience, which include television, digital, and radio media, press releases, social media, community events, bill inserts, mailings and electronic newsletters.

Q. The Coalition also asserts that gas safety materials for school children should not be recoverable as a Category A expense, because they are not gas utility service ratepayers.[35] Did the Company record gas safety materials for school children as a Category A communications expense?

A. No. As I explained above, these materials were recorded as a Category B expense. They are shared with schools and educators as members of the "Affected Public" per RP-1162.

Q. The Coalition also observes that federal law prohibits promotional and political advertising and suggests that the school safety materials should not be recoverable on that basis.[36] How do you respond?

A. As I have detailed above, the primary purpose for the materials is to educate about natural gas safety to keep educators, students, and their families safe. Because the primary purpose is public awareness of our safety message, I disagree that these materials should be considered political or promotional in nature.

[35] Coalition/400, Ryan/18.

[36] Coalition/400, Ryan/20.

Q. Apart from the gas safety educational materials for schools, did the Coalition raise any concerns about the Company's Category B expense?

A. No. My understanding is that the Coalition is primarily concerned with the gas safety educational materials for schools, but nonetheless asserted that all Category B advertising should be disallowed.[37]

Q. Does the Coalition's concern about the school materials justify disallowing the entire amount of Category B expense?

A. No. First, I believe that the Company has explained in detail why it is appropriate to record the school materials as Category B expense, and why the Company should get full cost recovery. Second, even if the Commission were to consider removing or disallowing some the expense associated with the school materials, it would only amount to about $62 thousand of expense, rather than the entire amount of $1.08 million for Category B communications expense.

V. <u>THE COALITION'S QUANTIFIABLE ADJUSTMENTS</u>

Q. The Coalition proposed disallowing all Category A and Category B expense. Does its testimony support that recommendation?

A. No. The Coalition provided personal opinion and criticism of specific topics of advertising included in the Company's Category A and Category B expense, but did not provide a justification for the wholesale disallowance of all of the Company's advertising expense.

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[37] Coalition/400, Ryan/4.

Q. Did you prepare an alternative calculation of the costs associated with the specific advertising topics that the Coalition raised regarding Category A and Category B advertising?

A. Yes. As shown in Table 1, below, the Oregon-allocated costs in the Base Year that supported (1) natural gas safety education materials provided to schools; (2) indoor air quality related advertising; and (3) RNG advertising totaled: $461,006.

Table 1. Base Year Category A and B Costs Disputed by the Coalition

Advertising Topics	OR Allocated Base-Year Cost	
Excerpt of March 2021 Comfort Zone Newsletter	$	3,000.00
Indoor Air Quality	$	13,200.00
School Safety Program	$	62,900.00
RNG Advertising	$	381,906.00
Total	**$**	**461,006.00**

Q. Were there other updates regarding the total level of expense in the Base Year?

A. Yes, as I mentioned above, in preparing this Reply Testimony, NW Natural discovered that for the Base Year, $124,221 in Oregon-allocated costs were charged to Category A that should have been charged to Category C for production of: NW Natural_ ConsumerInformation_Performance_TV.mp4.

Q. What is the total Oregon-allocated cost impact of the Coalition's proposed objections to Category A and B advertising and the adjustment for the costs that were inadvertently charged to Category A?

A. The total Oregon-allocated expense adjustment would be $585,227.

Q. How does the combined total Oregon-allocated cost impact of the Coalition's proposed objections to Category A and B advertising and the costs charged to Category A by mistake compare to the adjustment in the Stipulation?

A. Although the Coalition proposed disallowing all Category A and Category B expense, its testimony does not justify a full disallowance. Instead, if the Commission were inclined to agree with the Coalition's opinions and criticisms of Category A and Category B advertising, the adjustment would amount to $461,006. Taken together with the correction for the Category C costs that were inadvertently charged to Category A, it would amount to $585,227. The adjustment to advertising expense in the Stipulation is $1.0 million, which is considerably greater, and therefore demonstrates that the Stipulation resulted in a reasonable compromise on this issue. In light of the significant adjustment included in the Stipulation, no further reduction to advertising expense is warranted.

VI. CUSTOMER SURVEY EXPENSE

Q. Please describe the customer survey expense included in the Test Year.

A. NW Natural is requesting $53,000 of Oregon allocated O&M expense associated with customers surveys in the Test Year. The customer surveys are intended to better understand the interests and concerns of NW Natural's customers, so the messages published for customers are relevant and helpful. Importantly, one of the types of communications included in Category A is "contemporary items of customer interest." Thus, NW Natural must understand the issues that matter to its customers to best address their concerns.

Q. Are the surveys captured in the Category A or Category B communications expense?

A. No, they are booked to a separate account for market research.

Q. Was this issue addressed in the Stipulation?

A. Yes. As part of the Stipulation, NW Natural agreed to CUB's proposed adjustment regarding customer survey expense, which provided that the budget for customer surveys and focus groups be cut in half to reflect CUB's view that at least half of this activity is focused on concerns that primarily benefit shareholders.[38] The Stipulation included a $27,000 revenue requirement reduction associated with this adjustment.[39]

Q. Did the Coalition also comment on the customer survey expense?

A. Yes. The Coalition comments that NW Natural is performing these surveys to better understand its customers views, but does not appear to specifically propose an adjustment for this category of expense.

Q. Does this conclude your Reply Testimony?

A. Yes.

[38] CUB/100, Jenks/20.

[39] Stipulation at 5.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibits of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBITS 1901-1902

June 6, 2022

EXHIBITS 1901-1902 – CUSTOMER COMMUNICATIONS

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June 6, 2022

Public Awareness Programs for Pipeline Operators

API RECOMMENDED PRACTICE 1162
FIRST EDITION, DECEMBER 2003

Approved American National Standard
ANSI

American Petroleum Institute

Helping You Get The Job Done Right.[SM]

Public Awareness Programs for Pipeline Operators

Pipeline Segment

API RECOMMENDED PRACTICE 1162
FIRST EDITION, DECEMBER 2003

American Petroleum Institute

Helping You Get The Job Done Right.[SM]

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FOREWORD

This document is a Recommended Practice (RP) for pipeline operators to use in development and management of Public Awareness Programs. Pipeline Operators have conducted Public Awareness Programs with the affected public, government officials, emergency responders and excavators along their routes for many years. The goal of this RP is to establish guidelines for operators on development, implementation, and evaluation of Public Awareness Programs in an effort to raise the effectiveness of Public Awareness Programs throughout the industry.

Representatives from natural gas and liquid petroleum transmission companies, local distribution companies, and gathering systems, together with the respective trade associations, have developed this Recommended Practice. The working group was formed in early 2002. Additionally, representatives from federal and state pipeline regulators have provided input at each step of development and feedback from all interested parties has been solicited through a wide variety of sources and surveys.

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Public Awareness Programs for Pipeline Operators

1 Introduction, Scope and Glossary of Terms

1.1 INTRODUCTION

This Recommended Practice (RP) provides guidance to be used by operators of petroleum liquids and natural gas pipelines to develop and actively manage Public Awareness Programs. This RP will also help to raise the quality of pipeline operators' Public Awareness Programs, establish consistency among such programs throughout the pipeline industry, and provide mechanisms for continuous improvement of the programs. This RP has been developed specifically for pipelines operating in the United States, but may also have use in international settings.

Public awareness and understanding of pipeline operations is vital to the continued safe operation of pipelines. Pipeline operators' Public Awareness Programs are an important factor in establishing communications and providing information necessary to help the public understand that pipelines are the major transportation system for petroleum products and natural gas in the United States, how pipelines function, and the public's responsibilities to help prevent damage to pipelines.

Public Awareness Programs should address the needs of different audiences within the community and be flexible enough to change as the pipeline system changes or as the public's needs for information change. When effectively and consistently managed, a Public Awareness Program can provide significant value to the pipeline operator in several areas: enhanced public safety, improved pipeline safety and environmental performance, building trust and better relationships with the public along the pipeline route, less resistance to pipeline maintenance and right-of-way activities, preservation of rights-of-way, enhanced emergency response coordination, and improved pipeline operator reputation.

Public awareness messages need to provide a broad overview of how pipelines operate, the hazards that may result from activity in close proximity to pipelines and those hazards possible due to pipeline operations, and the measures undertaken to prevent impact to public safety, property or the environment. These messages should be coupled with information regarding how pipeline operators prepare for emergencies in a way that minimizes the consequences of a pipeline incident.

This RP identifies for the pipeline operator four specific stakeholder audiences and associated public outreach messages and communication methods to choose from in developing and managing a successful Public Awareness Program. It also provides information to assist operators in establishing specific plans for public awareness that can be evaluated and updated.

This RP is comprised of a main body (Sections 1 – 8), and Appendices. The main body of this document contains the general, baseline program recommendations and the supplemental program components. Summary tables and diagrams are also provided in the main body. These summaries can be used as quick reference guides to assist operators when customizing their Public Awareness Programs to reflect the unique characteristics of their pipeline and facilities. The Appendices provide operators with additional, optional information and resources for further reference. The Appendices repeat many areas of the main body in order to provide the operator with comprehensive information.

1.2 SCOPE

This RP is intended as a resource that can assist pipeline operators in their public awareness efforts. Operators are urged to develop, implement and actively manage Public Awareness Programs within their companies. In implementing these programs, operators should select the most appropriate mix of audiences, message types, and delivery methods and frequencies, depending on their needs and the needs of the communities along a given pipeline segment. The guidance set forth in this RP establishes a baseline for Public Awareness Programs and describes considerations for program expansion that can further enhance specific public awareness outreach.

This RP provides guidance for the following pipeline operators:

- Intrastate and interstate hazardous liquid pipelines
- Intrastate and interstate natural gas transmission pipelines
- Local distribution systems, and
- Gathering systems.

This guidance is intended for use by pipeline operators in developing and implementing Public Awareness Programs associated with the normal operation of existing pipelines. The guidance is not intended to focus on public awareness activities appropriate for new pipeline construction or for communications that occur immediately after a pipeline-related emergency. Communication regarding construction of new pipelines is highly specific to the type of pipeline system, scope of the construction, and the community and state in which the project is located. Likewise, public communications in response to emergency situations are also highly specific to the emergency and location. This RP is also not intended to provide guidance to operators for communications about operator-specific performance measures that are addressed through other means of communication or regulatory reporting.

The primary audience for this RP is the pipeline operator for use in developing a Public Awareness Program for the following stakeholder audiences:

- The affected public—i.e., residents, and places of congregation (businesses, schools, etc.) along the pipeline and the associated right-of-way (ROW)
- Local and state emergency response and planning agencies—i.e., State and County Emergency Management Agencies (EMA) and Local Emergency Planning Committees (LEPCs)
- Local public officials and governing councils
- Excavators.

DESCRIPTION OF PIPELINE INFRASTRUCTURE

To clarify the scope of the pipeline industry covered by this RP, a brief description of the affected infrastructure components is provided below. Mainline pipe, pump and compressor stations, and other facilities that are associated with the pipeline should be considered to be included. Unless otherwise noted, the use of the term "pipeline" in this RP will refer to all three of the following types of systems. The RP recognizes some differences between the three pipeline types and provides the operator flexibility based on the needs of the stakeholders along a particular pipeline.

1.2.1 Transmission Pipelines

The transmission pipeline systems for liquid petroleum and natural gas, move large amounts of liquids and natural gas from the producing and/or refining locations to local "outlets", such as bulk storage terminals (for liquids) and natural gas distribution systems. Transmission pipeline systems can be classified as either "intrastate pipelines", located within one state's borders, or "interstate pipelines" crossing more than one state's borders. Natural gas transmission pipelines deliver gas to direct-served customers and local distribution systems' stations, referred to as "city gates", where the pressure is lowered for final distribution to end users. Liquids transmission pipelines usually transport crude oil, refined products, or natural gas liquids. Transmission pipelines are generally the middle of the transportation link between gathering and distribution systems.

1.2.2 Local Distribution Systems

The local distribution systems for liquid petroleum and natural gas differ because of the nature and use of the products. Liquid petroleum products are distributed from bulk terminals by other modes of transportation, such as by rail cars and tank trucks. Local natural gas distribution companies (LDCs) receive natural gas at "city gates" and distribute it through distribution systems, These consist of "mains", which are usually located along or under city streets and smaller service lines that connect to the mains to further distribute natural gas service to the local end users - homes and businesses.

1.2.3 Gathering Systems

Gathering pipelines link production areas for both crude oil and natural gas to central collection points. Some gathering systems include processing facilities; others do not. Some gathering systems are regulated by the Office of Pipeline Safety, U.S Department of Transportation, while most are not. Gathering systems connect to transmission pipelines for long distance transportation of crude oil and natural gas to refinery centers and distribution centers, respectively.

1.3 GLOSSARY OF TERMS

1.3.1 Appendices: The Appendices' role is to provide a pipeline operator with additional information to develop and actively manage its Public Awareness Programs. The Appendices' mirror the main body of the RP while providing additional information such as: resources and contacts, examples of stakeholder audiences, public awareness messages, enhanced delivery methods and media, and program evaluation information.

1.3.2 Baseline Public Awareness Program: Refers to general program recommendations, set forth in Recommended Practice 1162, The baseline recommendations do not take into consideration the unique attributes and characteristics of individual pipeline operators' pipeline and facilities. Supplemental or enhanced program components are described in the RP to provide guidelines to the operator for enhancing its Public Awareness Programs. This is described more fully in Sections 2 and 6.

1.3.3 CFR: *Code of Federal Regulations*

1.3.4 Dig Safely: Dig Safely is the nationally recognized campaign to enhance safety, environmental protection, and service reliability by reducing underground facility damage. This damage prevention education and awareness program is used by pipeline companies, One-Call Centers, and others throughout the country. Dig Safely was developed through the joint efforts of the Office of Pipeline Safety and various damage prevention stakeholder organizations. Dig Safely is now within the purview of the Common Ground Alliance (CGA). For more information see www.commongroundalliance.com.

1.3.5 Enhanced Public Awareness Program: The concept developed in RP 1162 for assessing particular situations in which it is appropriate to enhance or supplement the Baseline Public Awareness Program. This is described more fully in Section 6.

1.3.6 High Consequence Areas (HCAs): A high consequence area is a location that is specially defined in pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. Pipeline safety regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, the protection of the HCA.

1.3.7 HVL (Highly Volatile Liquid): A highly volatile liquid, as defined in pipeline safety regulations, is a hazardous liquid that will form a vapor cloud when released to the atmosphere and has a vapor pressure exceeding 276kPa (40 psia) at 37.8 degrees C (100 degrees F).

1.3.8 Integrity Management Program (IMP): In accordance with pipeline safety regulations, an operator's integrity management program must include, at a minimum, the following elements:

- a process for determining which pipeline segments could affect a High Consequence Area (HCA)
- a Baseline Assessment Plan
- a process for continual integrity assessment and evaluation
- an analytical process that integrates all available information about pipeline integrity and the consequences of a failure
- repair criteria to address issues identified by the integrity assessment method and data analysis (the regulations provide minimum repair criteria for certain, higher risk, features identified through internal inspection)
- a process to identify and evaluate preventive and mitigative measures to protect HCAs
- methods to measure the integrity management program's effectiveness and
- a process for review of integrity assessment results and data analysis by a qualified individual.

1.3.9 IMP Overview: An overview of an operator's IMP program should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be a few pages and its availability could be mailed upon request or made available on the operator's website.

1.3.10 LDCs: Local Distribution Companies for natural gas

1.3.11 "may" versus "should": Clarification is necessary for RP 1162's use and definition of the words "may" versus "should":

- The use of the word "may" provides the operator with the option to incorporate the identified component into its Public Awareness Program.
- The use of the word "'should" provides the operator with the Public Awareness Program components that are recommended to be incorporated into the operator's Public Awareness Program.

1.3.12 NPMS: National Pipeline Mapping System (See Section 4.6.2)

1.3.13 One-Call Center: The role of the One-Call Center is to receive notifications of proposed excavations, identify possible conflicts with nearby facilities, process the information, and notify affected facility owners/operators.

1.3.14 Operator: All companies that operate pipelines that are within the scope of this RP.

1.3.15 OPS: Office of Pipeline Safety, part of the Research and Special Programs Administration (RSPA) of the U.S. Department of Transportation. OPS develops and enforces safety and integrity regulations for pipelines and pipeline operations.

1.3.16 Pipeline Right-of-Way (ROW): a defined strip of land on which an operator has the rights to construct, operate, and/or maintain a pipeline. A ROW may be owned outright by the operator or an easement may be acquired for specific use of the ROW.

1.3.17 Supplemental Public Awareness Program: Refer to the definition above, "Enhanced Public Awareness Program".

1.3.18 Third-Party Damage: outside force damage to underground pipelines and other underground facilities that can occur during excavation activities. Advanced planning, effective use of One-Call Systems, accurate locating and marking of underground facilities, and the use of safe digging practices can all be very effective in reducing third-party damage.

2 Public Awareness Program Development

The overall goal of a pipeline operator's Public Awareness Program is to enhance public environmental and safety property protection through increased public awareness and knowledge.

PUBLIC AWARENESS PROGRAM OBJECTIVES

2.1 OBJECTIVES

- **Public Awareness of Pipelines**

Public Awareness Programs should raise the awareness of the affected public and key stakeholders of the presence of pipelines in their communities and increase their understanding of the role of pipelines in transporting energy. A more informed public along pipeline routes should supplement an operator's pipeline safety measures and should contribute to reducing the likelihood and potential impact of pipeline emergencies and releases. Public Awareness Programs will also help the public understand that while pipeline accidents are possible, pipelines are a relatively safe mode of transportation, that pipeline operators undertake a variety of measures to prevent pipeline accidents, and that pipeline operators anticipate and plan for management of accidents if they occur. Finally, a more informed public will also understand that they have a significant role in helping to prevent accidents that are caused by third-party damage and ROW encroachment.

- **Prevention and Response**

Public Awareness Programs should help the public understand the steps that the public can take to prevent and respond to pipeline emergencies. "Prevention" refers to the objective of reducing the occurrences of pipeline emergencies caused by third-party damage (versus other causes under the control of the operator) through awareness of safe excavation practices and the use of the One-Call System. "Response" refers to the objective of communicating to the public the appropriate steps to take into account in the event of a pipeline release or emergency.

These objectives, together with others that may be identified by individual pipeline operators, provide the foundation on which a pipeline Public Awareness Program is built. Two important objectives of this RP include:

- Assist each pipeline operator to develop a framework for managing its Public Awareness Program so that the quality of Public Awareness Programs can be continually improved throughout the pipeline industry and
- Provide the operator with considerations to determine how to enhance its program to provide the appropriate level of public awareness outreach for a given area and certain circumstances.

2.2 OVERVIEW FOR MEETING PUBLIC AWARENESS OBJECTIVES

In general, Public Awareness Programs should communicate relevant information to the following stakeholder audiences (as defined in Section 3):

2.2.1 The Affected Public

- Awareness that they live or work near a pipeline
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to recognize and respond to a pipeline emergency
- What protective actions to take in the unlikely event of a pipeline release
- How to notify the pipeline operator regarding questions, concerns, or emergencies
- How to assist in preventing pipeline emergencies by following safe excavation/digging practices and reporting unauthorized digging or suspicious activity
- How community decisions about land use may affect community safety along the pipeline ROW
- How individuals can create undesirable encroachments upon a pipeline ROW
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas located in their area, land use practices, emergency preparedness or other matters.

2.2.2 Local Public Officials

- Information regarding transmission pipelines that cross their area of jurisdiction
- Land use practices associated with the pipeline ROW that may affect community safety
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operators with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction, land use practices, emergency preparedness or other matters.

2.2.3 Emergency Officials

- Location of transmission pipelines that cross their area of jurisdiction, and how to get detailed information regarding those pipelines
- Name of the pipeline operator and the emergency contact information for each pipeline
- Information about the potential hazards of the subject pipeline
- Location of emergency response plans with respect to the subject pipelines
- How to notify the pipeline operator regarding questions, concerns, or emergency
- How to safely respond to a pipeline emergency
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction,

land use practices, emergency preparedness or other matters.

2.2.4 Excavators

- Awareness that digging and excavating along the ROW may affect public safety, pipeline safety and/or pipeline operations
- Information about one-call requirements and damage prevention requirements in that jurisdiction
- Information about safe excavation practices in association with underground utilities
- How to notify the operator regarding a pipeline emergency or damage to a pipeline
- Hazards associated with unintended releases
- Name of the pipeline operator and who to contact for emergency or non-emergency information.

This RP focuses on those four segments of the public, as listed above, that are most directly affected by or could have the most affect on pipeline safety. The general public is a larger audience for general pipeline awareness information. General knowledge about energy pipelines is useful to the general public and may be obtained through a variety of sources, including the Office of Pipeline Safety, US Department of Transportation, pipeline industry trade associations and pipeline operators.

2.3 REGULATORY COMPLIANCE

This RP is intended to provide a framework for Public Awareness Programs designed to help pipeline operators in their compliance with federal regulatory requirements found in 49 *CFR* Parts 192 and 195.

The three principal compliance elements include:

2.3.1 Public Education (49 *CFR* Parts 192.616 and 195.440):

These regulations require pipeline operators to establish continuing education programs to enable the public, appropriate government organizations, and persons engaged in excavation-related activities to recognize a pipeline emergency and to report it to the operator and/or the fire, police, or other appropriate public officials. The programs are to be provided in both English and in other languages commonly used by a significant concentration of non-English speaking population along the pipeline.

2.3.2 Emergency Responder Liaison Activities (49 *CFR* Parts 192.615 and 195.402):

These regulations require that operators establish and maintain liaison with fire, police, and other appropriate public officials and coordinate with them on emergency exercises or drills and actual responses during an emergency.

2.3.3 Damage Prevention (49 *CFR* Parts 192.614 and 195.442):

These regulations require pipeline operators to carry out written programs to prevent damage to pipelines by excavation activities.

2.4 OTHER RESOURCES

In addition to operator personnel, various other resources are available to assist pipeline operators in developing their Public Awareness Programs and related informational materials. These resources can often shorten development time and reduce the implementation cost of an operator's Public Awareness Program. Some of these other resources are described below.

2.4.1 Trade Associations

The major pipeline industry trade associations take an active role in sponsoring various efforts that can help operators meet public awareness objectives. These trade associations include the:

- American Petroleum Institute (API)
- Association of Oil Pipe Lines (AOPL)
- American Gas Association (AGA)
- Interstate Natural Gas Association of America (INGAA) and
- American Public Gas Association (APGA).

The websites of these associations provide a wide range of information to assist operators in developing and managing Public Awareness Programs, and developing information to use in implementing those programs. The trade associations also undertake specific efforts in public outreach, such as:

- Printing of pipeline safety brochures that can be customized by the operator
- Development and distribution of pipeline safety decals and materials
- Development of videos and brochures to aid in the education of public officials regarding pipeline emergency response
- Development of website information specifically for pipeline public awareness
- Distribution of periodic newsletters that provide additional guidance and information to operators on issues related to Public Awareness Programs
- Development and sponsorship of television and radio public service announcements (PSA)
- Participation in appropriate trade shows to inform excavators, regulators, legislators, and others.

For additional information on these efforts, contact the trade associations directly. Contact information and website addresses are provided in Appendix A.

2.4.2 One-Call Centers

The primary purpose of a One-Call System is to prevent damage to underground facilities, including pipelines, which could result from excavation activities. All states and the District of Columbia have established One-Call Systems (some states may have two or more One-Call Systems). State One-Call Centers may develop public awareness information materials and may be able to gather extensive information about excavation contractors. If available to the pipeline operator, this information will be useful to fulfill the requirements of 49 *CFR* Part 192.614 and 195.442 (Damage Prevention Programs). Many One-Call Systems perform their own public awareness outreach through public service announcements and other advertising. Some One-Call Systems may also sponsor statewide excavation hazard awareness programs. One-Call System contacts can be found at the "Dig Safely" website (see Appendix A).

2.4.3 Federal and State Agencies

Although pipeline operators are the primary sponsors of Public Awareness Programs on pipeline safety, some state agencies with regulatory authority for pipeline safety can provide training and materials. In addition, some state pipeline safety regulatory agencies sponsor or conduct pipeline public awareness efforts. The federal agency responsible for pipeline safety, the Office of Pipeline Safety of the U.S. Department of Transportation, is also a source of relevant information.

2.4.4 Common Ground Alliance

The Common Ground Alliance (CGA) is a nationally recognized nonprofit organization dedicated to shared responsibility in damage prevention and promotion of the damage prevention Best Practices identified in the landmark *Common Ground Study of One-Call Systems and Damage Prevention Best Practices*. This report is available online from CGA's website (see Appendix A). Building on the spirit of shared responsibility resulting from the Common Ground Study, the purpose of the CGA is to ensure public safety, environmental protection, and the integrity of services by promoting effective damage prevention practices. The "Dig Safely" campaign is now a component of the Common Ground Alliance.

The Common Ground Alliance is supported by its sponsors, member organizations, the Office of Pipeline Safety, and individual members. CGA sponsorship and membership is open to all stakeholder organizations that want to support the CGA's damage prevention efforts.

2.4.5 Outside Consultants

Many outside consultants are available to support an operators' Public Awareness Program. Direct-mail vendors are capable of producing pipeline safety materials and providing distribution services. These vendors can assist operators in identifying residents and special interest groups, such as excavators along the pipeline route, and can support the operator in production and distribution of the material. Public relations firms are also available to assist operators in developing material specifically geared to the intended audience. Their expertise can help heighten the readability of the public awareness materials and improve the operator's overall success in communicating the intended message.

2.4.6 Other Pipeline Companies

Pipeline companies have developed a variety of creative ways to meet their public awareness objectives. Cooperative information exchanges or shared public awareness activities between operators can be beneficial and economical.

2.4.7 Operator Employee Participation

As members of communities and community service organizations, informed employees of a pipeline operator can play an important role in promoting pipeline awareness. An operator should include in its Public Awareness Program provisions for familiarizing its employees with its public awareness objectives. Information and material used by the operator should be made available to employees who wish to promote pipeline awareness in their communities. Many Public Awareness Programs include components for key employee training in public awareness and specific communication training for specific key employees.

Operator employees can be a key part of public awareness efforts. Grass-roots employee contacts and communications can be particularly important in effectively reaching out to a community. Employees who are interested in and capable of performing a greater public communication role should be given the necessary training, communications materials and, as appropriate, be provided with opportunities for direct involvement with the community.

2.5 MANAGEMENT SUPPORT

For a Public Awareness Program to achieve its objectives, ongoing support within the operator's organization is crucial. Management should demonstrate its support through company policy, management participation, and allocation of resources and funding. Funding and resource requirements for an operator's Public Awareness Program development and implementation will vary according to the program's objectives, design, and scope. Full organizational support can make a marked difference in the way the Public Awareness Program is received and can affect the overall effectiveness and success of the program.

2.6 BASELINE AND SUPPLEMENTAL PUBLIC AWARENESS PROGRAMS

For the development of a Public Awareness Program, this RP recognizes that there are differences in pipeline conditions, release consequences, affected populations, increased development and excavation activities and other factors associated with pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. For example, some geographic areas have a low population, low turn over in residents, and little development or excavation activity; whereas other areas have very high population, high turn over, and extensive development and excavation activity.

This RP provides the operator with the elements of a recommended baseline Public Awareness Program. It also provides the operator with considerations to determine when and how to enhance the program to provide the appropriate level of public awareness outreach. Details for assessing the need for program enhancement are presented in Section 6. The appropriateness of enhanced or supplemental messages, delivery frequency and methods, and/or geographic coverage area is also one aspect of program evaluation. Recommendations on the evaluation of Public Awareness Programs are presented in Section 8.

2.7 PROGRAM DEVELOPMENT GUIDE

It is recommended that pipeline operators develop a written Public Awareness Program. The following guide may be helpful to pipeline operators in the development and implementation of their Public Awareness Programs.

Overall Program Administration

Step 1. Define Program Objectives

- Define program objectives in accordance with Section 2 of this RP.

Step 2. Obtain Management Commitment and Support

- Develop a company Policy and "statement of support" for the Public Awareness Program. This should include a commitment of participation, resources, and funding for the development, implementation, and management of the program.
- Reference Section 2.5.

Step 3. Identify Program Administration

- Name program administrator(s)
- Identify roles and responsibilities
- Document program administration
- Reference Section 7.

Step 4. Identify Pipeline Assets to be Included within the Program

- The overall program may be a single Public Awareness Program for all pipeline assets, or may be divided into individual, asset-specific programs for one or more specific pipeline systems, one or more pipeline segments, one or more facilities, or one or more geographic areas. Smaller companies and LDCs may have just one overall program.
- Name an administrator for each asset specific program.
- Reference Section 7 for documentation.

Program Development (applied to each identified asset- specific program)

Step 5. Identify the Four Stakeholder Audiences

- Establish methods to be used in audience identification.
- Establish a means of contact or address list for each audience type:
  - Affected public
  - Emergency officials
  - Local public officials
  - Excavators.
- Document methods used and output.
- Reference Section 3 for detail on stakeholder audiences.

Step 6. Determine Message Type and Content for Each Audience

- Establish which message types are to be used with which audience(s).
- Determine content for each message type.
- Document message type and content selected.
- Reference Section 4 for details on message development.

Step 7. Establish Baseline Delivery Frequency for Each Message

- Suggested delivery frequencies are described in Section 2.8.
- Document delivery frequencies selected.

Step 8. Establish Delivery Methods to Use for Each Message

- Select appropriate methods.
- Utilize alternate methods as appropriate.
- Document delivery methods selected.
- Establish process for management of input/feedback/comments received.
- Reference Sections 2.8 and 5 for additional detail.

Step 9. Assess Considerations for Supplemental Program Enhancements

- Review the criteria in this RP for enhanced programs (e.g. supplemental activities).
- Assess pipeline assets contained in the program and apply supplemental program elements.
- Solicit input from appropriate pipeline personnel (e.g. pipeline operations and maintenance personnel, other support personnel, etc.).
- Apply identified supplemental program elements to the program.
- Document supplemental program elements (describes when, what, and where program enhancements are used).
- Reference Sections 2.8 and 6.

Step 10. Implement Program and Track Progress

- Develop resource and monetary budgets for program implementation.
- Identify, assign and task participating company employees needed to implement the program.
- Identify external resources or consultants needed.
- Conduct program activities (e.g. mass mailings, emergency official meetings).
- Periodically update the program with newly identified activities.
- Collect feedback from internal and external sources.
- Document the above. Reference Section 7 for documentation and record keeping recommendations.

Step 11. Perform Program Evaluation

- Establish an evaluation process.
- Determine input data sources (e.g. company surveys, industry surveys, reply cards, feedback from participating employees, and feedback from recipient audiences, etc.).
- Assess results and applicability of operator and/or industry-sponsored evaluations.
- Document evaluation results. Reference Section 8 for program evaluation recommendations.

Step 12. Implement Continuous Improvement

- Determine program changes or modifications based on results of the evaluation to improve effectiveness. Program changes may be areas such as: audience, message type or content, delivery frequency, delivery method, supplemental activities or other program enhancements.
- Document program changes.
- Determine future funding and internal and external resource requirements resulting from program changes made.
- Implement changes.

Return to Step 5; Initiate new cycle for updating the Public Awareness Program.

The figurative description of the program development process is shown below, highlighting the continuous nature of the development, implementation and evaluation process.

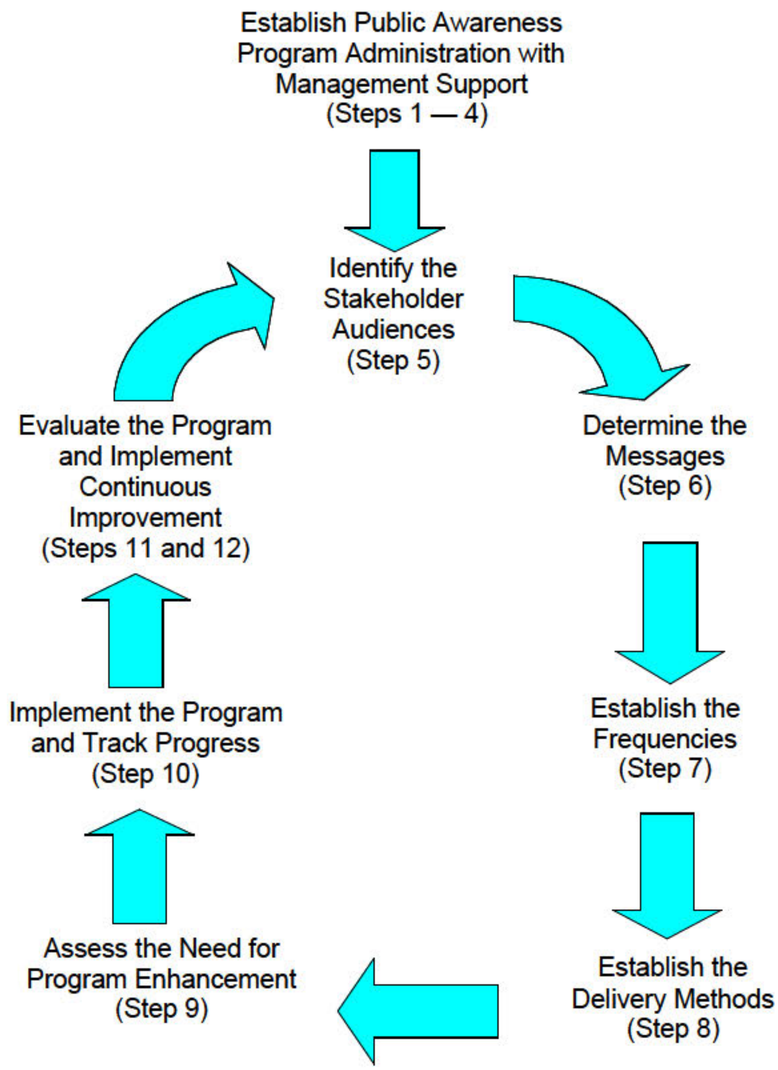

Figure 2-1—Public Awareness Program Process Guide

2.8 SUMMARY OF PROGRAM RECOMMENDATIONS

This RP has defined three categories of pipeline operators to which the RP applies. The three categories are:

1. Hazardous Liquid and Natural Gas Transmission Pipeline Operators (Table 2-1)
2. Local Natural Gas Distribution (LDC) Companies (Table 2-2)
3. Gathering Pipeline Operators (Table 2-3).

This RP recognizes that the communications and public awareness needs and activities may vary by the category of pipeline. Operators may customize their programs to best suit the needs of the stakeholder audiences and make them relevant to the type of potential hazards posed by their pipeline systems.

The tables 2-1 through 2-3 summarize the baseline recommendations for conducting public awareness for operators of Hazardous Liquid, Natural Gas Transmission, Local Natural Gas Distribution (LDC), and Gathering Pipelines. Guidance is also provided to assist the operators in determining if supplemental efforts affecting the frequency or method of message delivery and/or message content are called for, by evaluating the effectiveness of the program and the specifics of the pipeline segment or environment. Considerations for when and how an operator should implement program enhancements are described in Section 6. Further information of stakeholder audiences (Section 3); message types (Section 4); and message delivery methods (Section 5) may be found in their respective sections and related appendices.

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.1 Affected Public			
Residents located along transmission pipeline ROW **and** **Places of Congregation**	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	**Baseline Frequency =** 2 years	**Baseline Activity:** • Targeted distribution of print materials • Pipeline markers
	Supplemental Message: • Information and/or overview of operator's Integrity Management Program • ROW encroachment prevention • Any planned major maintenance/construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses
Residents near storage or other major operational facilities	**Supplemental Message:** • Information and/or overview of operator's Integrity Management Program • Special incident response notification and/or evacuation measures *if* appropriate to product or facility • Facility purpose	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency Preparedness Communications • Potential hazards • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency =** Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Message: • Provide information and /or overview of Integrity measures undertaken • Maintenance construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Emergency tabletop, deployment exercises • Facility tour • Open house
2-1.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • One-call requirements • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • If applicable, provide information about designation of HCA (or other factors unique to segment) and summary of integrity measures undertaken • ROW encroachment prevention • Maintenance construction activity	**Supplemental Frequency:** • If in HCA, then annual contact to appropriate public safety officials • Otherwise, as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency =** Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers
	Supplemental Messages: Pipeline purpose, prevention measures and reliability	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Group meetings
Land Developers	**Supplemental Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • One-call Requirements • Leak Recognition and Response • ROW Encroachment Prevention • Availability of list of pipeline operators through NPMS	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Pipeline markers • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.1 Affected Public			
Residents along the Local Distribution System (LDC)	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Public service announcements, OR • Paid advertising, OR • Bill stuffers (for combination electric & gas companies)
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Newspaper and magazines • Community events or • Community neighborhood newsletters
LDC Customers	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = Twice annually	**Baseline Activity:** • Bill stuffers
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials
2-2.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Print materials, OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Telephone calls • Personal contact • Videos and CDs
2-2.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Group meetings • Telephone calls • Personal contact

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies (Continued)

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Leak recognition and response • One-call requirements • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • One-Call Center outreach OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Videos and CDs • Open houses
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** • As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.1 Affected Public			
Residents, **and** **Places of Congregation within area of potential impact**	**Baseline Messages:** • Gathering pipeline purpose • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = 2 years	**Baseline Activity:** • Targeted distribution of print materials OR • Personal contact
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason.	**Supplemental Frequency:** • Annually for sour gas gathering lines • Additional frequency as determined by specifics of the pipeline segment or environment.	**Supplemental Activity:** • Pipeline markers • Print materials • Personal contact • Telephone calls • Group meetings • Mass media • Other activities described in Section 5

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Gathering pipeline location and purpose • Awareness of hazards • Prevention measures undertaken • Emergency preparedness communications, company contact and response information • Specific description of products transported and any potential special hazards • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason		**Supplemental Activity:** • Emergency tabletop deployment exercises • Facility tour • Open house
2-3.3 Local Public Officials			
Public Officials	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Copies of materials provided to affected public and emergency officials • Company contacts • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • ROW encroachment prevention • Maintenance construction activity • Special emergency procedures if sour gas or other segment specific reasons.	**Supplemental Frequency:** • If in HCA, then more frequent or annual contact with appropriate public safety officials • Otherwise as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers **Supplemental Activity:** • Personal contact • Group meetings • One-Call Center outreach • mass media
Land Developers	**Supplemental Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

3 Stakeholder Audiences

One of the initial tasks in developing a Public Awareness Program is to identify the audience(s) that should receive the program's messages. This section defines the intended audiences for the operator's Public Awareness Program and provides examples (not all inclusive) of each audience. Further explanation and examples are included in Appendix B. This information should help the operator clarify whom it is trying to reach with its program. The following audiences are considered "stakeholders" of the pipeline operator's Public Awareness Program. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

The operator should consider tailoring its communication coverage area to fit its particular pipeline location and release consequences. The operator would be expected to consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand its communication coverage area as appropriate.

The "Stakeholder Audience" definitions listed in the table below are used in the remaining sections of this RP, as applicable.

3.1 THE AFFECTED PUBLIC

Stakeholder Audience	Audience Definition	Examples
Residents located adjacent to the transmission pipeline ROW	People who live adjacent to a natural gas and/or hazardous liquid transmission pipeline ROW.	• Occupants or residents • Tenants • Farmers • Homeowners associations or groups • Neighborhood organizations
Residents located along distribution systems	People who live on or immediately adjacent to the land wherein gas distribution pipelines are buried.	• LDC customers • Non-customers living immediately adjacent to the land wherein distribution pipelines are buried
Gas transmission pipeline customers	Businesses or facilities that the pipeline operator provides gas directly to for end use purposes. This does not include LDC customers.	• Power plants • Businesses • Industrial facilities
LDC customers	People that are served by gas distribution facilities.	• LDC customers
Residents near liquid or natural gas storage and other operational facilities along transmission lines	People who live adjacent to or near a tank farm, storage field, pump/compressor station and other facilities.	• Occupants or residents tenants • Farmers • Homeowner associations or groups • Neighborhood organizations
Places of congregation	Identified places where people assemble or work on a regular basis—on or along a transmission pipeline ROW, unrelated to habitation.	• Businesses • Schools • Places of worship • Hospitals and other medical facilities • Prisons • Parks & recreational areas • Day-care facilities • Playgrounds
Residents located along rights-of-way for gathering pipelines	• People who live or work on land along which the gathering pipeline is located, and within the right-of-way. • For higher consequence gathering lines (e.g. H_2S), people who live or work a distance on either side of right-of-way that is based on the potential impact in the event of an emergency.	• Occupants or residents • Tenants • Farmers • Businesses • Schools

3.2 EMERGENCY OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Emergency officials	Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction along the pipeline route.	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • County and State Emergency Management Agencies (EMA) • Other emergency response organizations • Other public safety organizations

3.3 LOCAL PUBLIC OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Public officials	Local, city, county or state officials and/or their staffs having land use and street/road jurisdiction along the pipeline route.	• Planning boards • Zoning board • Licensing departments • Permitting departments • Building code enforcement departments • City and county managers • Public and government officials • Public utility boards • Includes local "Governing Councils" as defined by many communities • Public officials who manage franchise or license agreements

3.4 EXCAVATORS

Stakeholder Audience	Audience Definition	Examples
Excavators	Companies and local/state government agencies who are involved in any form of excavation activities.	• Construction companies • Excavation equipment rental companies • Public works officials • Public street, road and highway departments (maintenance and construction) • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Well drillers
Land developers	Companies and private entities involved in land development and planning.	• Home builders • Land developers • Real estate sales
One-Call Centers	Excavation One-Call Centers relevant to the area.	• Each state, region, or other organization established to notify underground facility owner/operators of proposed excavations. Excavation One-Call Centers relevant to the area.

4 Message Content

An operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. Information materials may also include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message conveyed to the intended audience should provide information that will allow the operator to meet the program objectives. The communications should include enough information so that in the event of a pipeline emergency, the intended audience will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator. Several components of these messages are discussed in this section.

4.1 PIPELINE PURPOSE AND RELIABILITY

Operators should consider providing a general explanation of the purpose of the pipeline and/ or facilities and the reliability of pipelines to meet the energy needs of the region, even though this is not a primary objective of pipeline public awareness. Operators should provide assurances that security is considered.

4.2 HAZARD AWARENESS AND PREVENTION MEASURES

Operators should provide a very broad overview of potential hazards, their potential consequences and the measures undertaken by the operator to prevent or mitigate the risks from pipelines (including, at the operator's discretion, an overview of the industry's safety record). Additionally, operators should provide an overview of their preventative measures to help assure safety and prevent incidents. The scope of the hazard awareness and prevention message should be more detailed for the emergency responder audience than for other audiences, and should include how to obtain more specific information upon request from the operator.

4.3 LEAK RECOGNITION AND RESPONSE

The pipeline operator should provide information in the following key subject areas to the affected public and excavator stakeholder groups.

4.3.1 Potential Hazards of Products Transported

Information about specific release characteristics and potential hazards posed by hazardous liquids or gases should be included.

4.3.2 How to Recognize a Pipeline Leak

Information should address how to recognize a pipeline leak through the senses of sight, unusual sound, and smell and describe any associated dangers as appropriate to the product type.

4.3.3 Response to a Pipeline Leak

Information should address an outline of the appropriate actions to take if a pipeline leak or release is suspected.

4.3.4 Liaison with Emergency Officials

Information should describe the ongoing relationship between the operator and local emergency response officials to help prevent incidents and assure preparedness for emergencies.

4.4 EMERGENCY PREPAREDNESS COMMUNICATIONS

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. Operators should provide a summary of emergency preparedness information to local public officials and should indicate that detailed information has been provided to emergency response agencies in their jurisdictions. The following information should be provided to the emergency officials stakeholder audience.

4.4.1 Priority to Protect Life

The operator's key messages to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

4.4.2 Emergency Contacts

Contact information for the operator's local offices and 24-hour emergency telephone line should be shared with local and state emergency officials. Operators should also use the contacts with emergency officials to confirm that both emergency officials and the operators have the current, correct contact information and calling priorities.

4.4.3 Emergency Preparedness Response Plans

Operators are required by federal regulations to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state emergency regulations. 49 *CFR* 192 and 195 and some state regulations outline the specific requirements for emergency response plans and who to contact for additional information. The operator should include information about how emergency officials can access the operator's emergency response plans covering their jurisdiction.

4.4.4 Emergency Preparedness—Drills and Exercises

A supplemental means of two-way communication about emergency preparedness is to establish a liaison with emergency response officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

4.5 DAMAGE PREVENTION

Because even relatively minor excavation activities can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the key "Dig Safely" messages developed by the Common Ground Alliance (CGA). CGA contact information is located in Appendix A.

The use of an excavation One-Call Notification system should be explained to the audience. Information on the prevalence of digging-related damage, also known as "third-party" damage, should be provided as appropriate. The audience should be requested to call the state or local One-Call System in their area before they begin any excavation activity. If the state or locality has established penalties for failure to use established damage prevention procedures, that fact may also be communicated, depending on the audience and situation. Additional information is located in Appendix C.

Additionally, third-party contractors are subject to the Occupational Safety and Health Administration's (OSHA) requirements. OSHA cites in its "General Duty Clause" possible regulatory enforcement action that could be taken against excavation contractors who place their employees at risk by not utilizing proper damage prevention practices. The lack of adequate damage prevention could subject the excavator to OSHA regulatory enforcement. OSHA contact information is located in Appendix A.

4.6 PIPELINE LOCATION INFORMATION

4.6.1 Transmission Pipeline Markers

The audience should know how to identify a transmission pipeline ROW by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. The operator's awareness communications should include information about what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in certain areas. As such, use of the One-Call Notification system should be encouraged. Additional detail is located in Appendix C.

4.6.2 Transmission Pipeline Mapping

Pipeline maps developed by transmission pipeline operators can be an important component of an operator's Public Awareness Program. The level of detail provided on the map should, at a minimum, include the line size, product transported and the approximate location of the pipeline, as well as any other information deemed reasonable and necessary by the operator. National energy infrastructure security issues should be considered in determining information and distribution related to pipeline maps. The public can also receive information about which pipelines operate in their community by accessing the National Pipeline Mapping System (NPMS). The NPMS will provide the inquirer a list of pipeline operators and operator contact information. Operators should include information on the availability of the NPMS within their public awareness materials. NPMS information is provided in Appendix A. Additional mapping information is provided in Appendix C.

4.7 HIGH CONSEQUENCE AREAS (HCAs) AND INTEGRITY MANAGEMENT PROGRAM OVERVIEW FOR TRANSMISSION OPERATORS

4.7.1 Message Content for Affected Public within HCAs

Public awareness materials should include a general explanation that, in accordance with federal regulations, some segments along transmission pipelines have been designated as High Consequence Areas (HCAs) and that supplemental hazard assessment and prevention programs (called Integrity Management Programs) have been developed. Information provided to the affected public should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.7.2 Message Content for Emergency Officials within HCAs

For emergency official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should include an overview of the operator's Integrity Management Programs. Inclusion of this information during emergency official liaison interface will provide an opportunity for feedback from the emergency official on the operator's Integrity Management Programs.

4.7.3 Message Content for Public Officials within HCA's

For public official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.8 CONTENT ON OPERATOR WEBSITES

Pipeline operators who maintain websites can include the following information (further examples of this information are provided in Appendix C):

- Company information
- General information on pipeline operations
- General or system pipeline map(s)
- Affected public information
- Emergency and security information
- Damage prevention awareness and One-Call Notification.

4.9 RIGHT-OF-WAY ENCROACHMENT PREVENTION

Pipeline operators should communicate that encroachments upon the pipeline ROW inhibit the operator's ability to respond to pipeline emergencies, eliminate third-party damage, provide ROW surveillance, perform routine maintenance, and perform required federal/state inspections. Stakeholder specific information is listed in Appendix D.

4.10 PIPELINE MAINTENANCE CONSTRUCTION ACTIVITIES

Pipeline maintenance-related construction activities should be communicated to the audience affected by the specific activity in a timely manner appropriate to the nature and extent of the activity.

4.11 SECURITY

Where applicable and in accordance with the national Homeland Security efforts, pipeline operators should communicate an overview pertaining to security of their pipelines and related facilities.

4.12 FACILITY PURPOSE

Where appropriate, communication with the affected public and emergency and public officials in proximity to major facilities (such as storage facilities, compressor or pump stations) should include information to promote understanding of the nature of the facility. Operators should communicate general information regarding the facility and product(s) stored or transported through the facility. Communication with emergency officials should also include emergency contact information for the specific facility.

5 Message Delivery Methods and/or Media

This section describes several delivery methods and tools available to pipeline operators to foster effective communications with the intended stakeholder audiences previously described. The operator is reminded that not all methods are effective in all situations. The content of the communication efforts should be tailored to:

- Needs of the audience
- Type of pipeline and/or facilities
- Intent of the communication, and
- Appropriate method/media for the content.

A more detailed discussion of the summary information below is provided in Appendix D.

5.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audience and message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed below.

5.1.1 Brochures, Flyers, Pamphlets, and Leaflets

Brochures, flyers, pamphlets and leaflets are probably the most common message delivery methods currently used by the pipeline industry. These print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. These print materials also afford an effective opportunity to communicate content in a graphical or pictorial way.

5.1.2 Letters

Research has indicated that letters mailed to residents along the pipeline ROW are an effective tool to communicate specific information, such as how to recognize and what to do in the event of a leak, how to identify and report suspicious activity, and notification of planned operator activities.

5.1.3 Pipeline Maps

Pipeline maps can be an important component of an operator's Public Awareness Program and should be considered where they can enhance the appropriate stakeholder(s) awareness of the operator's pipeline and facilities. Additional information regarding pipeline mapping is available in Appendix C.

5.1.4 Response Cards

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other items. The inclusion of a response card can be used in a variety of ways (refer to Appendix D).

5.1.5 Bill Stuffers

Bill stuffers are printed brochures frequently used by local distribution companies (LDCs) in conjunction with customer invoices. Due to the nature of customers for transmission and gathering pipelines, bill stuffers are not considered an appropriate option. LDCs using bill stuffers can easily reach their customers with appropriate messages and can increase their effectiveness by using bill stuffers repeatedly. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even those that may not be natural gas customers.

5.2 PERSONAL CONTACT

Personal contact describes face-to-face contacts between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication and allows for two-way discussion. Personal contacts may be made on an individual basis or in a group setting. Some examples of personal contact communications are described further in Appendix D and include:

- Door-to-door contact along pipeline ROW
- Telephone calls
- Group meetings
- Open houses
- Community events
- Charitable contribution presentations by pipeline companies.

5.3 ELECTRONIC COMMUNICATION METHODS

5.3.1 Videos and CDs

There are a variety of approaches operators may use to supplement their public awareness efforts with videos and CDs. While considered a supplement to the baseline components of an effective Public Awareness Program, videos and CDs may be quite useful with some stakeholders or audiences in some situations. These media can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual responses in ways that printed materials cannot.

5.3.2 E-mail

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholder audiences. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by postal mail or personal contact.

5.4 MASS MEDIA COMMUNICATIONS

5.4.1 Public Service Announcements

Public Service Announcements (PSAs) can be an effective means for reaching a large sector of the public. Radio and television stations occasionally make some airtime available for PSAs. They are no longer required by law to donate free airtime and as a result, there is great competition from various public interest causes for the small amount of time made available. If the operator is an advertiser with the radio or television station, this might be leveraged to gain advantage in acquiring PSA time.

5.4.2 Newspapers and Magazines

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline companies can submit or encourage reporters to write constructive and informative articles about pipeline issues, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure.

5.4.3 Paid Advertising

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community.

5.4.4 Community and Neighborhood Newsletters

Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with other outreach to those communities and/or neighborhoods. This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

5.5 SPECIALTY ADVERTISING MATERIALS

Specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These materials also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. The main benefit of this type of advertising is that it tends to have a longer retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods. Examples are included in Appendix D.

5.6 INFORMATIONAL OR EDUCATIONAL ITEMS

Companies can develop informational and educational materials to heighten pipeline awareness. The cost-effectiveness of producing such materials can be increased through partnering with an industry association or group of other operators.

5.7 PIPELINE MARKER SIGNS

The primary purposes of aboveground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency and
- Facilitate aerial or ground surveillance of the pipeline ROW by providing aboveground reference points.

Refer to Section 4 and Appendix C for additional information on marker sign types and information content.

Below-ground markers, such as warning tape or mesh, can also be effective warnings to excavators of the presence of buried pipe. When burying pipe following repairs, relocations, inspections, etc., operators should consider whether it is appropriate to add below-ground markers in the location.

5.8 ONE-CALL CENTER OUTREACH

Most state One-Call Centers provide community outreach or conduct public awareness activities about one-call requirements and damage prevention awareness, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such communication as a part of their own Public Awareness Programs. Many One-Call Centers host awareness meetings with excavators to further promote the damage prevention and one-call messages. It is the operator's responsibility to request documentation for these outreach activities.

To enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become one-call members in localities where they operate pipelines. Since all One-Call Center members share the center's public awareness outreach costs, the costs to an individual operator are usually comparatively low.

5.9 OPERATOR WEBSITES

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Additional information located in Appendix C.8 describes features for a company's pipeline operations that should fit into any corporate structure and overall website design. A company's website will supplement the other various direct outreach delivery tools discussed in this RP.

6 Recommendations for Supplemental Enhancements of Baseline Public Awareness Program

The pipeline operator has a number of stakeholder audiences for delivering messages regarding the safe operation of pipelines. The message content, the delivery medium, delivery frequency, and audience's retention of the delivered message should be carefully considered during the development and implementation of the operator's Public Awareness Program to achieve maximum effectiveness. Many of the communications should be available on demand or evergreen (e.g., websites, pipeline markers) and others are periodic in nature (e.g., mass mailings, public meetings, and advertisements). The combination of the specific messages, delivery methods, and delivery frequencies should be designed into the operator's program for each audience. These elements should allow each audience to develop and maintain an awareness of the pipeline's safe operation appropriate to the audience's responsibilities for pipeline awareness, response to pipeline emergencies, and its possible exposure to pipeline emergencies.

Section 2 includes summary tables of the overall Public Awareness Program recommendations. The summary tables include a baseline Public Awareness Program for the three pipeline categories. The tables also provide a recommended delivery frequency for each of the message types intended for the respective audiences. These frequencies are the suggested baselines and the pipeline operator should consider to what extent an enhanced, supplemental program is warranted.

The term "program enhancement" refers to the operator's decision to supplement its Public Awareness Program beyond the recommended baseline. Throughout this RP the terms "enhancement" and "supplemental" are used interchangeably and mean those communications measures added to the Public Awareness Program beyond the baseline program elements. To support this decision, the operator should consider external factors along the pipeline system and determine if some additional level of public awareness communications is warranted, beyond the recommended baseline program. Those supplemental aspects would then be incorporated into the Public Awareness Program for that pipeline segment or system. Supplemental enhancement considerations are discussed in detail on the following pages.

In addition, the operator should include in its Public Awareness Program Evaluation a periodic review and evaluation of its program (see Section 8), determine if supplemental public awareness efforts/activities are warranted and include those enhancements and related documentation into its program.

6.1 CONSIDERATIONS FOR SUPPLEMENTAL ENHANCEMENTS FOR THE BASELINE PROGRAM

This RP recognizes that there are differences in pipeline conditions, consequences, population, property development, excavation activities and other issues along pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. This RP recommends that an operator enhance its baseline program with supplemental program components when conditions along the pipeline suggest a more intensive effort is needed.

Baseline program recommendations are established for each of the three pipeline categories. The following sections are provided for guidance when the operator's consideration of relevant factors along the pipeline route indicates that supplemental program enhancement is warranted. Three primary forms of enhancement are provided for consideration in the development and administration of each Public Awareness Program:

6.1.1 Increased Frequency (Shorter Interval)

Increased frequency refers primarily to providing communications to specific stakeholder audiences on a more frequent basis (shorter interval) than the baseline recommended components to reach the intended audience.

6.1.2 Enhanced Message Content and Delivery/Media Efforts

Enhanced message content and delivery/media efforts refer to providing additional or supplemental communications activities beyond those identified in the baseline, using an enhanced or custom-tailored message content and/or different, or additional, delivery methods/media to reach the intended audience.

6.1.3 Coverage Areas

Coverage areas refer to broadening or widening the stakeholder audience coverage area beyond those contained in the baseline for delivery of certain communications messages. This can also be considered relative to widening the buffer distance for reaching the stakeholder audience along the pipeline route.

6.2 CONSIDERATIONS OF RELEVANT FACTORS

When the operator develops its Public Awareness Program and performs subsequent periodic program evaluations, it is recommended that a step for assessing relevant factors along the pipeline route be included to consider what components of the Public Awareness Program should be enhanced.

The operator should consider each of the following factors applied along the entire route of the pipeline system:

- Potential hazards
- High Consequence Areas
- Population density
- Land development activity
- Land farming activity
- Third-party damage incidents
- Environmental considerations
- Pipeline history in an area
- Specific local situations
- Regulatory requirements
- Results from previous Public Awareness Program evaluations
- Other relevant needs.

The presence of federally designated High Consequence Areas (HCAs) should prompt an operator to consider public awareness activity above the baseline level described in the RP. For natural gas transmission pipelines, 49 *CFR* Part 192.761 defines HCAs related to the population or places of congregation. For hazardous liquid transmission pipelines, 49 *CFR* Part 195.450 describes HCAs related to high population, Unusually Sensitive Areas (USAs) and navigable waterways.

Another factor to consider is the hazard associated with the pipeline as perceived by either the operator or the audience. For example, if a pipeline segment has experienced third-party damage, the operator could increase the frequency of messages to those third-parties and other relevant audiences. If the public's confidence in pipeline safety is undermined by a high profile emergency, even though an individual operator is experiencing no upward trend in incidents, that operator could consider expanding its public awareness communications to its public audiences to further increase awareness of its nearby pipeline system.

Further detail of considerations for program enhancement is discussed in the following sections.

6.3 HAZARDOUS LIQUID AND NATURAL GAS TRANSMISSION PIPELINE OPERATORS

Since Hazardous Liquids and Natural Gas Transmission pipelines are similar in many aspects with respect to public awareness, the two categories of pipelines have been combined.

Considerations for program enhancement for transmission pipelines could include, for example:

6.3.1 The Affected Public

Consideration should be given to *supplemental program enhancement* where:

- The occurrences indicate an elevated potential for third-party damage. Examples include:
  - A mailing to farmers along the right-of-way just prior to the deep plowing season where deep till plow methods are used
  - An additional or interim mass mailing to or face-to-face communications with residents of new housing developments in areas along the pipeline route that may not have previously been reached
  - Increasing the frequency of baseline communication efforts
- The pipeline runs through heavily developed urban areas that are more likely to have a frequently changing population than a more stable, less dense suburban or rural areas. Frequently changing population in an identified audience area should be considered when determining supplemental efforts to:
  - Residents in areas such as multi-family developments or densely populated urban areas
  - Increase the frequency of communications to residents
- Right-of-way encroachments have occurred frequently. Examples of supplemental efforts include:
  - Enhanced mailings to, face-to-face communications with, or increasing the frequency of communications to residents/developers/contractors in areas of right-of-way encroachment
- The potential for concern about consequences of a pipeline emergency is heightened. Consideration should be given to widening the coverage area for:
  - HVL pipelines in high population areas, extend the coverage area beyond the $^1/8^{th}$ mile minimum distance each side of the pipeline
  - Large diameter, high pressure, high volume pipelines where a pipeline emergency would likely affect the public outside of the specified minimum coverage area—extend the coverage area to a wider distance as deemed prudent.

6.3.2 Public Officials

Consideration should be given to *supplemental program enhancement* where:

- Heightened public sensitivity to pipeline emergencies exists in the area, independent of cause or which operator was involved
- Significant right-of-way encroachments (such as new construction developments) are occurring.

6.3.3 Emergency Officials

Consideration should be given to *supplemental program enhancement* where:

- Emergency officials have heightened sensitivity to pipeline emergencies
- After post-emergency review, or where there's potential for enhanced "liaison activities" between the operator and emergency officials that could have improved the emergency response to a pipeline emergency
- Requested by emergency officials to provide additional communications.

6.3.4 Excavators/Contractors and One-Call Centers

Consideration should be given to *supplemental program enhancement* where:

- There are instances that indicate an elevated potential for third-party damage
- Developers and contractors are performing a high number of excavations along a pipeline route in developing areas
- There are instances of problems identified with excavators' use or lack of use of the One-Call System. In those cases the operator should also request that the one-call Center perform additional public awareness outreach activities

6.4 LOCAL NATURAL GAS DISTRIBUTION COMPANIES (LDCs)

Many of the aspects of Public Awareness Programs for LDCs are similar to liquid and transmission pipeline operators. However, there are some differences because LDCs serve a different audience. Unlike transmission pipeline operators, LDCs have many more individual customers and have existing communication paths with those customers through monthly billing statements and other customer relationships. Table 2-2, for LDCs, in Section 2, provides baseline and supplemental communication recommendations for each of the different audiences.

Among LDCs there may be some variability in the frequency of communications with specific audiences. Public officials and emergency response personnel in a small rural city will likely be more accessible to the LDC pipeline operators than those in a major metropolitan area. Therefore, LDC operators should tailor their programs based on specific local considerations.

6.5 GATHERING PIPELINE OPERATORS

Gathering pipelines are usually small in diameter and operate at low pressures. In general, the audiences involved in public awareness communications for gathering pipelines tend to be in rural areas. The operator should tailor the specific communication program to fit the needs of the audiences and the circumstances in the particular area. Table 2-3 for gathering pipeline operators provides baseline and supplemental recommended communication frequencies for different audiences.

7 Program Documentation and Recordkeeping

Each operator should establish policies and procedures necessary to properly document its Public Awareness Program and retain those key records for purposes of program evaluation.

7.1 PROGRAM DOCUMENTATION

Each operator of a hazardous liquid pipeline system, natural gas transmission pipeline system, gathering pipeline system or a natural gas distribution pipeline system should establish (and periodically update) a written Public Awareness Program designed to cover all required components of the program described in this RP.

The written program should include:

a. A statement of management commitment to achieving effective public/community awareness.
b. A description of the roles and responsibilities of personnel administering the program.
c. Identification of key personnel and their titles (including senior management responsible for the implementation, delivery and ongoing development of the program).
d. Identification of the media and methods of communication to be used in the program, as well as the basis for selecting the chosen method and media.
e. Documentation of the frequency and the basis for selecting that frequency for communicating with each of the targeted audiences.
f. Identification of program enhancements, beyond the baseline program, and the basis for implementing such enhancements.
g. The program evaluation process, including the evaluation objectives, methodology to be used to perform the evaluation and analysis of the results, and criteria for program improvement based on the results of the evaluation.

In addition, some operators are required to have an Operations and Maintenance Procedure (O&MP) manual under 49 *CFR* Part 192 or 195. While the overall written program will likely be too extensive and schedule-specific to be suitable for an O&MP manual, the operator should include in the manual an overall statement of management commitment, roles and responsibilities (by group or title), a requirement for a written program and evaluation process, and a summary of the operator's Public Awareness Program.

7.2 PROGRAM RECORDKEEPING

The operator should maintain records of key program elements to demonstrate the level of implementation of its Public Awareness Program. Record keeping should include:

a. Lists, records or other documentation of stakeholder audiences with whom the operator has communicated.
b. Copies of all materials provided to each stakeholder audiences.
c. All program evaluations, including current results, follow-up actions and expected results.

7.3 RECORD RETENTION

The record retention period for each category in Section 7.2 should be a minimum of five (5) years, or as defined in the operator's Public Awareness Program, whichever is longer.

8 Program Evaluation

This section provides guidance to operators on how to periodically evaluate their Public Awareness Programs. The overall written plan for the Public Awareness Program should include a section describing the operator's evaluation program that includes the baseline elements described in the following paragraphs. Also included are suggestions for operators to consider in periodically supplementing their evaluation efforts in a particular segment, with a selected stakeholder audience or to provide greater depth of evaluation. This section includes only a brief description of each element. Appendix E provides additional explanations and examples for operator personnel who are new to developing Public Awareness Program evaluations.

8.1 PURPOSE AND SCOPE OF EVALUATION

The primary purposes of the evaluation of the Public Awareness Program are to:

- Assess whether the current program is effective in achieving the objectives for operator Public Awareness Programs as defined in Section 2.1 of this RP, and
- Provide the operator information on implementing improvements in its Public Awareness Program effectiveness based on findings from the evaluation(s).

A secondary purpose for Public Awareness Program evaluation is to demonstrate to company management and regulators, for pipelines subject to federal or state pipeline safety jurisdiction, the status and validity of the operator's Public Awareness Programs.

8.2 ELEMENTS OF EVALUATION PLAN

A program evaluation plan should include the measures, means and frequency for tracking performance. The selected set of measures should reflect:

- Whether the program is being implemented as planned—**the process**
- Whether the program is effective—**program effectiveness**.

Based on the results of the evaluation addressing these two questions, the operator may need to make changes in the program implementation process, stakeholder identification effort, messages, means and/or frequency of delivery. The sections below suggest specific measures and methods recommended to complete a baseline evaluation of the Public Awareness Program.

8.3 MEASURING PROGRAM IMPLEMENTATION

The operator should complete an annual audit or review of whether the program has been developed and implemented according to the guidelines in this RP. The purpose of the audit is to answer the following two questions:

- Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described Section 2 and the remainder of this RP?
- Has the Public Awareness Program been implemented and documented according to the written program?

Appendix E includes a sample set of questions that will aid an operator in auditing the program implementation process.

The operator should use one of the following three alternative methodologies when completing an annual audit of program implementation.

- Internal self-assessments using, for example, an internal working group, or
- Third-party audits where the evaluation is undertaken by a third-party engaged to conduct an assessment and provide recommendations for improving the program design or implementation, or
- Regulatory inspections, undertaken by inspectors working for federal or state regulators who inspect operator pipeline programs subject to pipeline safety regulations.

8.4 MEASURING PROGRAM EFFECTIVENESS

Operators should assess progress on the following measures to assess whether the actions undertaken in implementation of this RP are achieving the intended goals and objectives:

- Whether the information is reaching the intended stakeholder audiences
- If the recipient audiences are understanding the messages delivered
- Whether the recipients are motivated to respond appropriately in alignment with the information provided
- If the implementation of the Public Awareness Program is impacting bottom-line results (such as reduction in the number of incidents caused by third-party damage).

The following four measures describe how the operator should evaluate for effectiveness:

8.4.1 Measure 1—Outreach: Percentage of Each Intended Audience Reached with Desired Messages

This is a basic measurement indicating whether the operator's public awareness messages are getting to the intended stakeholders. A baseline evaluation program should establish a methodology to track the number of individuals or entities reached within an intended audience (e.g., households, excavating companies, local government, and local first responder agencies). Additionally, this measure should estimate the percentage of the stakeholders actually reached within the target geographic region along the pipeline. This measurement will help to evaluate the effectiveness of the delivery methods used.

- **Supplemental measures:** Other indicators that an operator may want to consider tracking as a supplement to measuring program outreach effectiveness include:
    - Track the number of inquiries by phone to operator-personnel or to the public awareness portions of an operator's website (however operators are cautioned that unless such information is specifically sought by the operator, this measure would not define if the caller or website viewer is a member of the target stakeholder audience nor whether this measure includes counts of repetitive website reviewers)
    - Track input received via feedback postcards (often called reply or bounce-back cards) from representatives of the stakeholder audience at events or meetings, sent by mail, or as a result of the operator's canvassing of the rights-of-way
    - Track the number of officials or emergency responders who attend emergency response exercises (this is an indicator of interest and the opportunity to gain knowledge).

8.4.2 Measure 2—Understandability of the Content of the Message

This measure would assess the percentage of the intended stakeholder audience that understood and retained the key information in the message received. This measurement will help to evaluate the effectiveness of the delivery media and the message style and content. This measurement will also help to assess the effectiveness of the delivery methods used.

- **Pre-test materials:** Operators should pre-test public awareness materials for their appeal and the messages for their clarity, understandability and retain-ability before they are widely used. A pre-test can be performed using a small representative audience, for example, a small sample group of operator employees not involved in developing the Public Awareness Program, a small section of the intended stakeholder audience or others (often referred to as focus groups described more fully in Appendix E).
- **Survey target stakeholder audiences:** An effective method for assessing understandability is to survey the target stakeholder audience in the course of face-to-face contacts, telephone or written surveys. Sample surveys are included in Appendix E. Factors to consider when designing surveys include:
  - Sample size appropriate to draw general conclusions
  - Questions to gauge understandability of messages and knowledge or survey respondent
  - Retention of messages
  - Comparison of the most effective means of delivery.

Program effectiveness surveys are meant to validate the operator's methodologies and the content of the materials used. Upon initial survey, improvements should be incorporated into the program based on the results. Once validated in this initial manner, a program effectiveness survey is only required about every four years. However, when the operator introduces major design changes in its Public Awareness Program a survey to validate the new approaches may be warranted.

An operator may choose to develop and implement its own program effectiveness survey in-house; have a survey designed with the help of third-party survey professionals; or participate in and use the results of an industry group or trade-association survey. If the latter approach is used, the industry or trade-association survey should allow the operator to assess the results relevant to the operator's own pipeline corridors and Public Awareness Programs.

8.4.3 Measure 3—Desired Behaviors by the Intended Stakeholder Audience

This measure is aimed at determining whether appropriate prevention behaviors have been learned and is taking place when needed and whether appropriate response or mitigation behaviors would occur and have taken place. This is a measure of learned and, if applicable, actual reported behavior.

- **Baseline evaluation:** The survey conducted as the means of assessing Measure 2 (above) should be designed to include questions that ask respondents to report on actual behaviors following incidents.
- **Supplemental evaluation:** As a supplement to these measures, operators may also want to assess whether the Public Awareness Program successfully drove other behaviors. Operators may consider the following examples as a supplemental means of assessing this measure:
  - Whether excavators are following through on all safe excavation practices, in addition to calling the One-Call Center
  - The number of notifications received by the operator from the excavation One-Call Center (e.g. is there a noticeable increase following distribution of public awareness materials?)
  - An assessment of first responder behaviors, including the response to pipeline-related calls, and a post-incident assessment to determine whether their actions would be and were consistent with the key messages included in the public awareness communications. Assessments of actual incidents should recognize that each response would require unique on-scene planning and response to specifics of each emergency.
  - Measuring the appropriateness of public stakeholders' responses is also anecdotal but could include tracking whether an actual incident that affected residents was correctly identified and whether reported and personal safety actions undertaken were consistent with public awareness communication.

8.4.4 Measure 4—Achieving Bottom-Line Results

One measure of the "bottom-line results" is the damage prevention effectiveness of an operator's Public Awareness Program and the change in the number and consequences of third-party incidents. As a baseline, the operator should track the number of incidents and consequences caused by third-party excavators. This should include reported near misses; reported pipeline damage occurrences that did not result in a release; and third-party excavation damage events that resulted in pipeline failures. The tracking of leaks caused by third-party excavation damage should be compared to statistics of pipelines in the same sector (e.g. gathering, transmission, local distribution). While third-party excavation damage is a major cause of pipeline incidents, data regarding such incidents should be evaluated over a relatively long period of time to determine any meaningful trends relative to the operator's Public Awareness Program. This is due to the low frequency of such incidents on a specific pipeline system. The operator should also look for other types of bottom-line measures. One other measure that operators may consider is the affected public's perception of the safety of pipelines.

8.5 SUMMARY OF BASELINE EVALUATION PROGRAM

Table 8-1—Summary of Baseline Evaluation Program

The results of the evaluation need to be considered and revisions/updates made in the public awareness program plan, implementation, materials, frequency and/or messages accordingly

Evaluation Approaches	Evaluation Techniques	Recommended Frequency
Self Assessment of Implementation	Internal review, ***or*** third-party assessment ***or*** regulatory inspection	Annually
Pre-Test Effectiveness of Materials	Focus groups (in-house or external participants)	Upon design or major redesign of public awareness materials or messages
Evaluation of effectiveness of program implementation: • Outreach • Level of knowledge • Changes in behavior • Bottom-line results	1. Survey: Can assess outreach efforts, audience knowledge and changes in behavior • Operator-designed and conducted survey, or • Use of pre-designed survey by third-party or industry association, or • Trade association conducted survey segmented by operator, state or other relevant separation to allow application of results to each operator. 2. Assess notifications and incidents to determine anecdotal changes in behavior. 3. Documented records and industry comparisons of incidents to evaluate bottom-line results.	No more than four years apart. Operator should consider more frequent as a supplement or upon major redesign of program.
Implement changes to the Public Awareness Program as assessment methods above suggest.	Responsible person as designated in written Public Awareness Program	As required by findings of evaluations.

APPENDIX A—RESOURCE CONTACT INFORMATION

A.1 Trade Associations

American Petroleum Institute
www.api.org
1220 L Street, NW
Washington, DC 20005

Association of Oil Pipe Lines
www.aopl.org
1101 Vermont Avenue, NW, Suite 604
Washington, DC 20005

American Gas Association
www.aga.org
400 N. Capitol Street, NW
Washington, DC 20001

American Public Gas Association
www.apga.org
11094-D Lee Highway, Suite 102
Fairfax, VA 22030-5014

Interstate Natural Gas Association of America
www.ingaa.org
10 G Street NE, Suite 700
Washington, DC 20002

A.2 Government Agencies

Office of Pipeline Safety
www.ops.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Rm. 7128
Washington, DC 20590-0001

The National Pipeline Mapping System (OPS/DOT)
www.npms.rspa.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Room 7128
Washington, DC 20590-0001

Transportation Safety Institute
www.tsi.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
6500 South MacArthur Blvd.
Oklahoma City, OK 73169

Occupational Safety and Health Administration
www.osha.gov
"Hazards Associated with Striking Underground Gas Lines"
www.osha.gov/dts/shib/shib_05_21_03_sugl.pdf

A.3 Private Organizations

Common Ground Alliance
www.commongroundalliance.com

Dig Safely
www.digsafely.com

A.4 Publications

The AGA's Gas Pipeline Technology Committee's GPTC Guide—ASC GPTC Z-380.1

APPENDIX B—EXAMPLES OF STAKEHOLDER AUDIENCES

When a Public Awareness Program is being developed, one of the initial tasks is to identify the audience(s) that should receive the program's messages. Section 3 identified the intended audiences for the operator's Public Awareness Program and included a "Stakeholder Audience Definition Table". This appendix will provide further examples. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

B.1 Stakeholder Audience Identification

Identification of the individual stakeholder audiences (i.e., members of the four target audiences) may be done by any means available to the operator. Several methods are available. Operators may identify their stakeholder audiences on their own or may elect to hire outside consultants who specialize in audience identification. Where lists are developed, they should be kept current or redeveloped prior to effecting a particular communication.

B.1.1 AFFECTED PUBLIC

Some examples of how an operator may determine specific affected public stakeholder addresses along the pipeline, such as within a specified distance either side of the pipeline centerline, include the use of nine-digit zip code address databases and geo-spatial address databases. These databases generally provide only the addresses and not the names of the persons occupying the addresses. Broad communications to this audience are typically addressed to "Resident." It is important to note that when contacting apartment dwellers, individual apartment addresses should be used, not just the address of the apartment building or complex.

Some operators maintain "line lists" which provide current information on names and addresses of people who own property on which the pipeline is located. It should be noted, however, that not all property owners live on the subject property and that the program should address those people living on the property. Additionally, where the operator has a customer base, the operator can use its customer databases for identifying audience members.

For the sub-groups "Residents located along transmission pipeline ROW" and "Places of Congregation," it is recommended that transmission pipeline operators provide communications within a minimum coverage area distance of 660 feet on each side of the pipeline, or as much as 1000 feet in some cases. The transmission pipeline operator should tailor its communications coverage area (buffer) to fit its particular pipeline, location, and potential impact consequences. At a minimum, operators should consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand the coverage area accordingly.

A sub-set of the affected public that the operator may desire to send specific public awareness materials to is farmers. Farmers engage in deep plowing and clearing activities that could impact pipelines. One method of determining names and addresses of farmers along a pipeline route is the use of third-party vendors who purchase periodicals databases related to the farming and agricultural community. Due to the size of farming operations in some areas and the proximity of farming residents, it is recommended that the operator increase its affected public awareness mailing coverage as appropriate.

B.1.2 EMERGENCY OFFICIALS

There are several methods used by operators to identify the names and addresses of emergency officials. Depending upon the size of the county or parish, this may include all emergency officials in the affected jurisdiction.

The means used by many operators is through the use of SIC (Standard Industrial Classification) code. Where SIC codes are utilized to identify emergency officials, the operator should include the list of code categories applicable to the emergency officials stakeholder group.

The pipeline operator should consider all appropriate emergency officials who have jurisdiction along the pipeline route and should communicate with any emergency officials that the operator deems appropriate for a given coverage area. This will generally include all emergency officials whose jurisdictions are traversed by the pipeline.

B.1.3 LOCAL PUBLIC OFFICIALS

Operators use several methods to identify names and addresses for specific public officials. These primarily include the use of local company resources, local phone books, and the Internet. Where SIC codes are used to identify public officials, the operator should include the categories applicable the public officials stakeholder group.

B.1.4 EXCAVATORS

While "excavators" is a broad category, its use here is intended to identify companies that perform or direct excavation work. Operators should identify, on a current basis, persons who normally engage in excavation activities in the areas in which the pipeline is located. There are several methods used by pipeline operators to identify specific excavator stakeholder names and addresses.

Where SIC codes are used to identify excavators, the operator should include the categories applicable to the Excavator stakeholder group. The SIC/NAICS list should be considered the minimum for excavator audience identification where those codes are used. The operator may add to or expand the list as other excavator information becomes available. Another source for identifying excavators is the One-Call Center that covers the area designated by the Public Awareness Program. Several One-Call Centers provide "excavator lists" to their members. This may also be accomplished by the use of a third-party vendor who specializes in this service.

APPENDIX C—DETAILED GUIDELINES FOR PUBLIC AWARENESS MESSAGES

Section 4 of this RP recommends that an operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. This appendix expands that recommendation by providing further explanation or examples of the content of messages to be communicated.

Information materials may include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message is conveyed to the intended audience should provide information that will allow the operator to meet the program objectives set forth in Section 2. The communications should include enough information so that in the event of a pipeline emergency, the intended audience members will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator.

C.1 Pipeline Purpose and Reliability

While not a primary objective, pipeline operators should consider providing general information about pipeline transportation, such as:

- The role of pipelines in U.S. energy supply
- Pipelines as part of the energy infrastructure
- Efficiency and reliability of pipelines
- Positive messages about the energy transportation pipeline safety record
- The individual operator's pipeline safety actions and environmental record.

For local distribution companies:

- Typical distribution network (stations, mains, services, meters)
- How to detect a natural gas leak (e.g., how natural gas smells)
- Who uses natural gas and why.

Many of these messages are available in print and videos from the pipeline industry trade associations listed in Section 2 and Appendix A.

The operator should describe the purpose and function of the pipeline and/or associated facilities and the nature, uses, and purposes of the products transported. Where practical, it might be helpful to communicate the benefit(s) of the pipeline to the community. Examples of "benefits" include:

- "This pipeline provides gasoline to motorists at X gas stations in the area of Y."
- "This natural gas pipeline network provides gas to X thousands of homes and businesses in Y city or Z state."

Pipelines are a safe and reliable means of transporting energy. Where appropriate, operators should describe how pipelines are a reliable means of transporting energy products and point out that they are extensively regulated by Federal and State regulations with regard to design, construction, operation and maintenance. Operators may also describe applicable operational activities that promote pipeline integrity, safety and reliability, which could include initial and periodic testing practices, internal inspections and their frequency, patrolling types and frequencies, and other such information. Operators may also reference the National Transportation Safety Board finding that pipelines provide the highest level of public safety as compared to other transportation modes.

C.2 Hazard Awareness and Prevention Measures

C.2.1 OVERVIEW OF POTENTIAL HAZARDS

General information about the nature of hazards posed by pipelines should be included in the message, while also assuring the stakeholder audience that accidents are relatively rare. The causes of pipeline failures, such as third-party excavation damage, corrosion, material defects, worker error, and events of nature can also be communicated.

C.2.2 OVERVIEW OF POTENTIAL CONSEQUENCES

Information should identify the product release characteristics and potential hazards that could result from an accidental release of hazardous liquids or gases from the pipeline.

C.2.3 SUMMARY OF PREVENTION MEASURES UNDERTAKEN

The potential hazard message should be coupled with a general overview of the preventative measures undertake by the operator in the planning, design, operation, maintenance, inspection and testing of the pipeline. This message should also reinforce how the stakeholder audience can play an important role in preventing third-party damage and right-of-way encroachments.

C.2.4 OPTIONAL SUMMARY OF PIPELINE INDUSTRY SAFETY RECORD

Depending on the stakeholder audience and the delivery methods used, the operator may want to consider including a general overview of the industry's safety record.

Communication materials should also convey the qualification that the information provided on hazards, consequences and preventative measures is very general and that more specific information could be obtained from the operator or other sources (noting phone or website(s) for contacts). Information communicated to emergency responders needs to be more specific, provide an opportunity for two-way feedback and include additional details on the products transported, facilities located within the jurisdiction and the local emergency planning liaison. Operators may want to consider referring to publications or websites produced by the trade associations listed in Appendix A for specific example language developed to provide overviews of hazards, consequences and preventative measures tailored to each stakeholder audience.

C.3 Leak Recognition and Response

The pipeline operator should provide the following information to the affected public and excavator stakeholder groups. To accomplish this, operators may want to consider using generic or standard printed materials developed by trade associations as aides for their member companies. However, operators will need to ensure the materials used are specific to the type of pipeline and product(s) transported in their systems.

C.3.1 POTENTIAL HAZARDS

Specific information about the release characteristics and potential hazards posed by the accidental release of hazardous liquids or gases from the pipeline should be included in the operator's communications.

C.3.2 RECOGNIZING A PIPELINE LEAK

Operators should include in their communications information on how to recognize a pipeline leak through the senses of sight, unusual sound, and smell (as appropriate to the product type) and describe any associated dangers.

- By Sight—What to Look for...
- By Sound—What to Listen for...
- By Smell—What to Smell for...

C.3.3 RESPONDING TO A PIPELINE LEAK

Operators should include in their communications an outline of the appropriate actions to take once a pipeline leak or release is suspected. This information should include:

- What to do if a leak is suspected
- What not to do if a leak is suspected.

It is especially important to include specific information on detection response if the pipeline contains product that, when released, could be immediately hazardous to health (e.g. high concentration of hydrogen sulfide).

C.3.4 LIAISON WITH EMERGENCY OFFICIALS

This information should indicate that both the operator and the local emergency response officials have an ongoing relationship designed to prepare and respond to an emergency.

C.4 Emergency Preparedness Communications

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. The following information should be provided to the emergency officials stakeholder audience. Local public officials should be provided a summary of the information that is available in more detail from the emergency response agencies in their jurisdictions.

C.4.1 PRIORITY TO PROTECT LIFE

Operator emergency response plans and key messages relayed to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

C.4.2 EMERGENCY CONTACTS

Contact information on the operator's local offices and 24-hour emergency telephone numbers should be communicated to local and state emergency officials. Operators should also use the public awareness contact opportunity to confirm the contact information for the local and state emergency officials and calling priorities.

C.4.3 EMERGENCY PREPAREDNESS—RESPONSE PLANS

Operators are required by federal regulation to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state regulations. 49 *CFR* 192 and 194 and some state regulations outline the specific requirements for emergency response plans. In developing Emergency Response Plans, the operator should work with the local emergency responders to enhance communications and response to emergencies.

C.4.4 EMERGENCY PREPAREDNESS—DRILLS AND EXERCISES

A very effective means of two-way communication about emergency preparedness is the liaison with emergency officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

C.5 Damage Prevention

Because even relatively minor excavation activities (for example: installing mail boxes, privacy fences and flag poles, performing landscaping, constructing storage buildings, etc.) can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the damage prevention best practices developed by the Common Ground Alliance (CGA).

The use of an excavation One-Call Notification system should be explained to the audience. The audience should be reminded to call the state or local One-Call System before beginning any excavation activity and that in most states it is required by law. Information on the prevalence of "third-party" damage should be provided as appropriate. If the state or locality has established penalties for failure to use established damage prevention procedures, that information may also be communicated, depending on the audience and situation.

As a baseline practice, excavation and one-call Information should include:

- Request that everyone contact the local One-Call System before digging
- Explain what happens when the One-Call Center is notified
- Provide the local or toll-free One-Call Center telephone numbers
- Explain that the one-call locate service is typically free (Note: Some exceptions by state)
- Remind, if applicable, that to call is required by law.

One-Call Center telephone numbers for all 50 states can be found at the Dig Safely website or by calling the Dig Safely national referral number at 1-888-258-0808.

The "Dig Safely" message should be included in public awareness materials distributed to the affected public and excavators by the operator in its communications:

- Call the One-Call Center before digging
- Wait for the site to be marked
- Respect the marks
- Dig with care.

For information see the "Dig Safely" website listed in Appendix A. Operators may also consider use of the widely recognized "No Dig" symbol in their materials.

C.6 Pipeline Location Information

C.6.1 TRANSMISSION PIPELINE MARKERS

The audience should know how to identify transmission pipeline rights-of-way by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. Communications should include what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in some areas.

Public awareness materials should include illustrations and descriptions of pipeline markers used by the operator and the information that the markers contain. Displaying the penalties for removing, defacing, or otherwise damaging a pipeline marker may also be beneficial.

In addition to meeting applicable federal and state regulations, transmission pipeline markers may:

- Indicate a pipeline right-of-way (not necessarily the exact pipeline location)
- Identify the product(s) transported
- Provide the name of the pipeline operator
- Provide the operator's telephone number, available 24-hours a day and 7-days a week
- Be brightly colored and highly visible
- Have weather resistant paint and lettering
- Include "Warning Petroleum Pipeline" or "Warning Gas Pipeline" and show the universal "No Dig" symbol
- Provide a one-call number.

Additional guidance for liquid pipeline marker design, installation, and maintenance is provided in API Recommended Practice 1109.

C.6.2 TRANSMISSION PIPELINE MAPPING

Transmission pipeline maps can be an important component of an operator's Public Awareness Program. The level of detail in the map provided will be relevant to the stakeholder's need, taking security of the energy infrastructure into consideration.

Members of the general public can also receive information about operators who have pipelines that might be located in their community by accessing the National Pipeline Mapping System (NPMS) on the Internet. The NPMS will provide the inquirer a list of pipeline operators and contact information for operators having pipelines in a specific area. Inquiries are made by zip code or by county and state. Operators should include information on the availability of the NPMS within their public awareness materials.

Following is a summary of the types of maps that are referred to in this RP in describing how operators can incorporate pipeline maps in their efforts to improve public awareness.

- *System Maps*—Typically system maps provide general depiction of a pipeline transmission system shown on a state, regional or national scale. This type of map generally is not at a scale that poses security concerns and is often used by operators in a number of publications available to the industry and general public. A system map generally depicts a portion of the pipeline system shown in relationship to a region of the country. Generally these types of maps do not include any detail on the location of facilities.

- *General Maps*—General maps are another form of system map, which may be presented, in a more graphical format or smaller scale.
- *Local Maps*—Local maps are generally shown on a neighborhood, town, city or county level and usually do not show the entire pipeline system. Local maps are especially appropriate in communication with local emergency officials, One-Call Centers and elected public officials. Local maps should be distributed in accordance with regulatory or operator's company security guidelines. Local maps could include pipeline alignment maps, GIS-system produced maps, or other types of mapping that show more detail about the physical location of the pipeline system.
- *Community Pipeline Infrastructure*—Maps of communities that depict all of the natural gas and liquid transmission pipeline systems in the area. Available from the state or OPS to public and emergency officials.
- *National Pipeline Mapping System (NPMS)*—The U.S. Department of Transportation's Office of Pipeline Safety has developed the National Pipeline Mapping System, through which pipeline location maps are made available electronically to state and local emergency officials, in accordance with federal security measures.

Operators of transmission pipelines should make available appropriate system or general maps to the affected public and provide them guidance in how they can determine the location of the pipelines near where they live and work. Such maps should include company and emergency contact information and a summary of the type of products transported.

As part of the damage prevention program, all operators should also communicate the process for contacting the excavation One-Call System so that the specific location of the pipeline (and other nearby utilities) can be marked prior to excavation activity.

Operators of transmission pipelines should make available local maps to public and emergency officials in their effort to assure effective emergency preparedness and land use planning. In addition, operators must follow regulatory guidelines on providing such maps as required under 49 *CFR* Part 192 and 195. Maps should include company and emergency contacts, information on the type of products transported, and sufficient detail on landmarks, roads or location information relevant to the official's needs.

Operators should provide paper or digitized maps, or alternative information to the state or regional excavation One-Call Center, consistent with the One-Call System's requirements.

C.7 High Consequence Areas and Integrity Management Program (IMP) Overview for Transmission Pipelines

C.7.1 MESSAGE CONTENT FOR AFFECTED PUBLIC WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of Integrity Management Program (IMP) Plans for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry. The information should make system maps of HCAs available to the general or affected public. An overview of an operators IMP should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The summary may only be a few pages long and its availability could be mailed upon request or made available on the operator's website.

C.7.2 MESSAGE CONTENT FOR EMERGENCY OFFICIALS WITHIN HCAs

When conducting liaison activities with emergency officials required by the public awareness plan, operators should include information on how the emergency official may gain access to the National Pipeline Mapping System for their jurisdiction through the Office of Pipeline Safety. In addition, the operator may supplement their messages and materials by including overviews of IMPs and specifically solicit feedback from the emergency official about local conditions or activities that may be useful and/or prompt changes to the operator's IMP for that area. For example, mitigation measures that may be included in a HCA segment's risk analysis and action plan is supplemental emergency response planning, staging area identification or equipment deployment. A two-way discussion with emergency officials of the components of the HCA risk mitigation plan would be helpful.

C.7.3 MESSAGE CONTENT FOR PUBLIC OFFICIALS WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of IMPs for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry.

An overview of an operator's IMP plan should include a description of the basic requirements and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be several pages long and its availability could be mailed upon request or made available on the operator's website.

C.8 Content on Company Websites

The information listed below will guide pipeline operators who maintain websites on the recommended informational components to be included on the website.

C.8.1 COMPANY INFORMATION

In addition to describing the purpose of the pipeline and markets served, the website should include a general description of the pipeline operator and system. This could include:

- Operator and owner name(s)
- Region and energy market served
- General office and emergency contacts telephone numbers and e-mail addresses
- Products being transported by pipeline
- System or general map and location of key offices (headquarters, region or districts).

C.8.2 INFORMATION ON PIPELINE OPERATIONS

A broad overview of the operator's pipeline safety and integrity management approach should be included describing the various steps the company takes to ensure the safe operation of its pipelines. While not specifically recommended, additional information to consider for the website includes:

- General pipeline system facts
- An overview of routine operating, maintenance and inspection practices of the system
- An overview of major specific inspection programs and pipeline control and monitoring programs.

C.8.3 TRANSMISSION PIPELINE MAPS

A general or system map (see previous section describing types of maps) should be on the website. Details on how to obtain additional information should be provided, including reference to the National Pipeline Mapping System ((NPMS).

C.8.4 PUBLIC AWARENESS PROGRAM INFORMATION

The operator should include a summary of its Public Awareness Program developed under the guidance of this RP and should consider including printed material used in these efforts on the website. The public should also be provided information on company contacts to request additional information.

C.8.5 EMERGENCY INFORMATION

The website should contain emergency awareness information from two aspects. First, it should contain a summary of the operator's emergency preparedness. Second, it should contain information about how the public, and residents along the pipeline rights-of-way, and/or public officials should help protect, recognize, report and respond to a suspected pipeline emergency. Emergency contact information should be prominent and accessible from anywhere on the pipeline portion of the website.

C.8.6 DAMAGE PREVENTION AWARENESS

Pipeline operators are encouraged to either provide or link the viewer to additional guidance on preventing excavation damage, such as "Dig Safely" program information, contact information for the One-Call System in each of the states in which the operator has pipelines, and the "Common Ground Alliance" website noted in Appendix A.

C.9 Right-of-way Encroachment Prevention

Pipeline operators should communicate that encroachments upon the pipeline right-of-way inhibit the operator's ability to reduce the chance of third-party damage, provide right-of-way surveillance and perform routine maintenance and required federal/state inspections. The communication can describe that in order to perform these critical activities, pipeline maintenance personnel must be able to access the pipeline right-of-way, as provided in the easement agreement. It should also describe that to ensure access; the area on either side of the pipeline contained within the right-of-way must be maintained clear of trees, shrubs, buildings, fences, structures, or any other encroachments that might interfere with the operator's access to the pipeline. It should also point out that the landowner has the obligation to respect the pipeline easement or right-of-way by not placing obstructions or encroachments within the right-of-way, and that maintaining a pipeline right-of-way free of encroachments is an essential element of maintaining pipeline integrity and safety.

Residents, excavators, and land developers should be requested to contact the pipeline operator if there are questions concerning the pipeline or the right-of-way, especially if property improvements or excavations are planned that might impact the right-of-way. These audiences should also be informed that they are required by state law to provide at least 48 hours advance notice, more in some states, to the appropriate One-Call Center prior to performing excavation activities. Longer lead times for planning major projects are advised and sometimes required by state law.

Operators should consider communicating with local authorities regarding information concerning effective zoning and land use requirements/restrictions that will protect existing pipeline rights-of-way from encroachment. Communications with local land use officials could include consideration of:

- How community land use decisions (e.g. planning, zoning,) can impact community safety
- Establishing setback requirements for new construction and development near pipelines

- Requiring prior authorization from easement holders in the permit process so that construction/development does not impact the safe operation of pipelines
- Requiring pipeline operator involvement in road widening or grading, mining, blasting, dredging, and other activities that may impact the safe operation of the pipeline.

C.10 Communication of Pipeline Maintenance Activities

When planning pipeline maintenance-related construction activities, operators should communicate to the audience affected by the activity in a manner that is appropriate to the nature and extent of the activity. For major maintenance construction projects (such as main-line rehabilitation or replacement projects) operators should also notify appropriate emergency and local public officials and include information on further communications appropriate to the nature or local impact of the maintenance or construction activity. Operators should communicate appropriately in accordance with requirements associated with the acquisition of permits.

C.11 Security

Operators should include in their communications, where applicable, appropriate information pertaining to security of their pipelines and related facilities. Communications messages could include:

- General information about the pipeline or aboveground facility security measures
- Increased public awareness about security
- Communications to pipeline and facility neighbors to:
    - Become familiar with the pipelines in their area (identification via pipeline marker signs)
    - Become familiar with the pipeline facilities in their area (identification via fence signs at gated entrances)
    - Record the operator name, contact information and any pipeline information from nearby pipeline marker signs or facility signs and keep in a permanent location near the telephone
    - Be observant for any unusual or suspicious activities and unauthorized excavations taking place within or near the pipeline right-of-way or pipeline facility. Report such activities to their local law enforcement and the pipeline operator.

Pipeline neighbors are the operator's first line of defense against unauthorized excavation and other such activity in the right-of-way, and they can help by contacting the operator or the proper local authorities of suspicious activities if they have contact information available.

C.12 Facility Purpose

Communication with the affected public, emergency and public officials in proximity of major facilities (such as storage facilities, compressor or pump stations) should include an understanding of the nature of the facility. Operators should include in their communications general information about the facility and the product(s) stored or transported through the facility. Liaison with emergency officials should also include an understanding of emergency contact information for the specific facility.

APPENDIX D—DETAILED GUIDELINES FOR MESSAGE DELIVERY METHODS AND/OR MEDIA

Section 5 describes the delivery methods and tools available to pipeline operators to foster effective communication programs with the stakeholder audiences previously described. This Appendix expands on those guidelines by providing further explanation or examples of delivery methods and/or media. This section does not imply that all methods are effective in all situations. The content of the communication efforts should be tailored to the needs of the audience and the intent of the communication. Refer to Section 4 for a detailed description of the message content that the following materials or delivery methods should contain for each intended audience.

D.1 Print Materials

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audiences and the message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed here.

D.1.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

This is the most common message delivery mechanism currently used by the pipeline industry. Print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. Print materials also afford an effective opportunity to communicate content in a graphical or pictorial way. However, note that targeted distribution of print materials alone should not be considered effective communication with local emergency response personnel.

Consideration should be given to joining with other pipeline companies in a local, regional or national setting (including both the local distribution company and transmission pipelines) to produce common message materials that can be either jointly sponsored, (e.g., include all sponsors company names/logos) or used as a "shell" and then customized to each company's individual needs, to help ensure that a consistent message is being delivered. This approach can also effectively reduce the cost to individual operators.

Print materials can be mailed to residents or communities along the pipeline system or handed out at local community fairs, open houses, or other public forums. Operators can hire facilitators to organize mass mailings, using nine-digit zip codes or geo-spatial address databases; to designated residents in the community located along the pipeline, such as within an appropriate distance either side of the pipeline centerline. In this case it is often advisable to get information from the postal service or service provider on size, folding and closure requirements to minimize the postage costs for mass mailings. There are services that can handle the printing of materials, mailing address identification, mailing and documentation for the operator as a package.

D.1.2 LETTERS

Research has indicated that letters mailed to residents along a pipeline system are an effective tool for the operator to use to communicate specific information, such as what to do in the event of a leak, identification of suspicious activity or notification of planned maintenance activities within the right-of-way.

Notification letters are usually effective where there is a high likelihood for third-party damage such as in agricultural areas, new developments and where other types of ground-disturbing activities may take place. Similar letters may also be send to contractors, excavators and equipment rental companies informing them of the requirement to use One-Call Systems and providing other important safety information for their workers and the public.

Letters, along with other print materials, should provide information about where the recipient can obtain further information (such as website address, e-mail address, local phone numbers and one-call numbers).

D.1.3 PIPELINE MAPS

Pipeline maps can be presented as printed material and are an important component of an operator's Public Awareness Program. The operator should consider whether maps should be part of the communications to appropriate local stakeholder(s), and what type of maps should be used to accomplish the objective. See Appendix C.6.2 for further explanation of types and availability of maps.

D.1.4 RESPONSE CARDS

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other print materials. When delivering public awareness information to nearby residents, public or emergency officials, the inclusion of response cards can be used in a variety of ways:

- To maintain/update current mailing lists. Response cards permit the recipients to notify the operator of any changes in address
- To provide a convenient venue for recipients to provide comments, request additional information, raise concerns or ask questions
- To help evaluate the effectiveness of the operator's Public Awareness Program.

D.1.5 BILL STUFFERS

Bill stuffers are printed materials frequently used by local distribution companies (LDCs) in conjunction with invoice mailings to their customers. Due to the nature of their customers, these are not an appropriate option for transmission and gathering pipelines. LDCs using bill stuffers can increase the effectiveness of their programs by communicating to their active customers frequently through the repeated use of bill stuffers. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even when some may not be natural gas customers.

D.2 Personal Contact

Personal contact describes face-to-face contact between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication, and it allows for two-way discussion. This may be done on an individual basis or in a group setting. Some examples of communications through personal contact are described below:

D.2.1 DOOR-TO-DOOR CONTACT ALONG PIPELINE RIGHT-OF-WAY

This method is often used to make contact with residents along the pipeline right-of-way to relay pipeline awareness information or information on upcoming pipeline maintenance. This method can help to build stakeholder trust, which is an integral part of communication and an enhancement to the long-term Public Awareness Program. Operator representatives conducting door-to-door contact should be knowledgeable and courteous, be prepared for these types of communications and be able to discuss and respond to questions relating to the communication materials provided so that contact is meaningful and positive. They should provide the landowner/resident with basic pipeline safety information and a means for future contact.

If pipeline safety is to be discussed in this forum, the operator representative should be generally knowledgeable about the company's pipeline integrity program and emergency response procedures. In addition to the general information described in Section 4, the following additional information should also be considered:

a. Description of facilities on or near the property (i.e., pipelines, meter/regulator stations, compressor/pump stations, wellheads, treating facilities, tankage, line markers, cathodic protection, communication, etc.)
b. Description of easement and property owner's rights and limitations within the easement
c. Name and phone number of local contact within company for further information and the operator's emergency notification number to report emergencies or suspicious activity
d. Information on damage prevention and local "Call Before You Dig" programs
e. What to do in case of emergency (fire, leak, noise, suspicious person)
f. Informational items (i.e., calendar, magnetic card, pens, hats, etc.) to retain important telephone numbers
g. As appropriate, additional local information such as upcoming maintenance, projects, events and/or company community involvement such as United Way, other charities, environmental projects, etc.

D.2.2 TELEPHONE CALLS

When the intended audience is small in number, the operator may find it effective to communicate by telephone. This personal form of contact allows for two-way discussion. The operator should decide which elements of their Public Awareness Program are suitable for conducting via telephone calls.

D.2.3 GROUP MEETINGS

Group meetings can be an effective way to convey the messages to selected audiences. Meetings may be between the operator (or group of operators) and an individual stakeholder audience or between the operator (or group of operators) and a number of the stakeholder audience groups at one time.

For example, the operator could conduct individual meetings with emergency response officials, combined industry meetings with emergency response officials, and participation by emergency response officials and personnel in the operator's emergency response tabletop drills and deployment exercises. Meetings are particularly effective in conducting liaison activities with the emergency official stakeholder group.

Another example is group meetings conducted by the operator in classrooms and with educators at local schools. Informational materials can be presented to school administrators and students and can contain important public awareness messages for students to take home to their parents. This method of personal contact can readily reach a large number of people with the operator's public awareness messages and reinforce positive messages about the operator and/or the pipeline industry.

Additional group meetings could include those with state One-Call System events, local excavators, contractors, land developers, and municipalities.

D.2.4 OPEN HOUSES

Operators often hold open houses to provide an informal setting to introduce an upcoming project, provide a "get to know your neighbor" atmosphere or to discuss an upcoming maintenance activity such as pipeline segment replacement. Tours of company facilities, question and answer sessions, videos, or presentations about pipeline safety and reliability do well in an open house environment. Even without formal presentations, allowing the public to see the facility can also be very effective. Often this type of forum would include refreshments and handouts (e.g. print material, trinkets, etc.) that attendees can take with them. Targeted or mass mailings can be used to announce planned open houses and can, in themselves, communicate important information.

D.2.5 COMMUNITY EVENTS

Community sponsored events, fairs, charity events, or civic events may provide appropriate opportunities where public awareness messages can be communicated to the event participants. Companies can participate with a booth or as a sponsor of the event.

These forums are generally used to remind the community of the operator's presence, show support for community concerns, and heighten public awareness about the benefits of pipeline transportation and about pipeline safety. Examples of community events include:

- County and state fairs
- Festivals and shows
- Job fairs
- Local association events
- Trade shows (Energy Fair)
- Chamber of Commerce events.

Operators should plan in advance and secure a large number of handout materials; as such events often include a large number of attendees and can take place over several days.

D.2.6 CHARITABLE CONTRIBUTIONS BY PIPELINE OPERATORS

While contributions to charities and civic causes are not in themselves a public awareness effort, companies should consider appropriate opportunities where public awareness messages can be conveyed as part of or in publicity of the contribution. Examples include:

- Contribution of gas detection equipment to the local volunteer fire department
- Donation of funds to acquire or improve nature preserves or green space
- Sponsorship to the community arts and theatre
- Support of scholarships (especially when to degree programs relevant to the company or industry)
- Sponsorship of emergency responders to fire training school.

D.3 Electronic Communications Methods

D.3.1 VIDEOS AND CDs

There are a variety of approaches companies may use to supplement their delivery tools with videos. While a supplement to the baseline components of an effective Public Awareness Programs, videos may be quite useful with some stakeholders or audiences in some situations. Videos can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual response that printed materials often cannot. Companies may seek industry specific videos from trade organizations or develop their own customized version. Such videos can be used for landowner contacts, emergency official meetings, or the variety of community or group meetings described elsewhere in this section. Companies could also consider adding such videos to their company websites.

D.3.2 E-MAIL

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholders. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by mail, by person or in meetings.

E-mail contact information can be provided on company handouts, magazine advertisements, websites and other written communications. This provides an effective mechanism for the public to request specific information or to be placed on distributions lists for specific updates.

An advantage of e-mail is the ease of requesting and receiving return information from the recipient, similar to contact information, survey or feedback described in bounce-back cards explained above. Note that it is important for the operator to designate a response contact within the organization to handle follow-up responses to e-mail queries in a timely manner.

D.4 Mass Media Communications

D.4.1 PUBLIC SERVICE ANNOUNCEMENTS (PSAs)

Radio and television stations occasionally make airtime available for public service announcements. There is great competition from various public interest causes for the small amount of time available because the broadcast media is no longer required by law to donate free airtime for PSAs. Given the popularity of radio and television and the large areas covered by both, public service announcements can be an effective means for reaching a large sector of the public. Pipeline operators (or groups of pipeline operators) could consider contacting local stations along the pipeline route to encourage their use of the PSAs. The use of cable TV public access channels may also be an option.

D.4.2 NEWSPAPERS AND MAGAZINES

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline operators can encourage reporters to write constructive stories about pipeline issues in various topics of relevance, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure. Even if the reporter is covering an emergency or controversial issue, pipeline operators can leverage the opportunity to reinforce key safety information messages such as damage prevention and the need to be aware of pipelines in the community. Trade magazines such as those for excavators or farmers often welcome guest articles or submission or assistance in writing a positive, safety-minded story for their readers. Local weekly newspapers and "metro" section inserts will sometimes include a news release verbatim at no cost to the sender.

D.4.3 PAID ADVERTISING

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community. This type of advertising can be very expensive, but can be made more cost effective by joining with other pipelines, including the local utilities, to deliver a consistent message. One example is placement of a public awareness advertisement on a phone book cover, thus achieving repetitive viewing by the audience for a whole year. Another example is advertising in local shopping guides.

D.4.4 COMMUNITY AND NEIGHBORHOOD NEWSLETTERS

Information provided should be similar to that made available for newspapers and magazines. Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with outreach to those communities and/or neighborhoods and is usually done for free. Operators can also develop their own newsletters tailored to specific communities. These newsletters can be used to highlight the operator's involvement in that community, provide the operator's public awareness messages, and to address any pipeline concerns that community may have.

This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

D.5 Specialty Advertising Materials

Company specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These tools also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. Many such materials or items exist, including refrigerator magnets, calendars, day planners, thermometers, key chains, flashlights, hats, jackets, shirts, clocks, wallet cards, and other such items containing a short message (i.e. "Call Before You Dig"), the company logo and/or contact information. The main benefit of this type of advertising is that it tends to have a longer retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods.

D.6 Informational Items

Operators can develop (or participate in industry associations or along with other companies) informational materials for groups or schools that heighten pipeline awareness. Operators (and their industry associations) may also sponsor or develop training materials for emergency response agencies that are designed to increase knowledge and skills in responding to pipeline emergencies. Alternatively, local emergency officials will hold training as part of their own continuing education, and attendance by pipeline personnel at these sessions is often welcome and an ideal setting for relaying public awareness information about pipelines.

D.7 Pipeline Marker Signs

The primary purposes of above ground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency
- Facilitate aerial or ground surveillance of the pipeline right-of-way by providing aboveground reference points.

Refer to Section 4 for additional information on marker sign types and information content.

Below ground markers are also effective warnings. While some may not consider this part of a proactive public awareness communication program, buried warning tape or mesh can be an effective reminder to excavators of the presence of underground utilities and have proven effective in preventing damage to pipelines and other buried utilities.

D.8 One-Call Center Outreach

Most state One-Call Centers provide community outreach or implement public awareness activities about the one-call requirements and the Dig Safely awareness messages, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such Public Awareness Programs within their own Public Awareness Program. Some One-Call Centers focus on hosting awareness meetings with excavators to further promote the Dig Safely and One-Call Messages. It is the operator's responsibility to request documentation for these outreach activities.

In order to enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become members of one-call organizations in areas where they operate pipelines. Since all underground facility members share One-Call Center public awareness outreach costs, the costs to an individual operator are usually comparatively low, and can demonstrate effectiveness by increased use of the One-Call Notification system.

D.9 Operator Websites

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Since corporate websites may vary in serving the business needs of the company (e.g. investor relations, marketing, affiliate needs), the guidance in Appendix C.8 describes features of the components of a website for a company's pipeline subsidiary or operations that should fit into any corporate structure and overall website design. Many pipeline operators may choose to place additional or more detailed information on their websites to supplement their public awareness and informational efforts.

An operator's website will supplement the other various direct outreach delivery tools discussed in this RP.

APPENDIX E—ADDITIONAL GUIDELINES FOR UNDERTAKING EVALUATIONS

This appendix provides additional explanation for several methods described in Section 8 for conducting program evaluations and provides a sample survey.

E.1 Focus Groups (Interview Panels)

A focus group is a group of people representative of one or more target audiences who are gathered to provide feedback about the materials or other aspects of a planned Public Awareness Program or to comment on an existing one.

Typically, a focus group has about 6 to 12 participants. While focus groups can be professionally facilitated, feedback about public awareness materials can be gained by an informal discussion run by individuals connected with the public education program. Often participants will be asked to review draft materials and to comment on what they understood from the materials and whether the materials would draw appeal when received by mail. Focus groups can also be used to provide input on the relative effectiveness of various means of delivery.

Focus group participants might be operator employees who are not familiar with the Public Awareness Program, citizens living along a stretch of pipeline or representatives of homeowner associations or business people along the right-of-way. Target stakeholder audiences should not be mixed. The participants usually are not chosen at random but rather are selected to be reasonably representative of their focus group and capable of articulating their reactions to the materials.

E.2 Sample Assessment of Program Implementation

Table E-1—Sample Audit of Program Implementation

I Program Development and Documentation: Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described in Section 2 and the remainder of this RP?
1. Does the operator have a written Public Awareness Program?
2. Have all of the elements described in Section 2 of this RP been incorporated into the written program?
3. Does the written program address all of the objectives of this RP as defined in Section 2.1?
4. Does the documented program address regulatory requirements identified in Section 2.2 of this RP and other regulatory requirements that the operator must comply with?
5. Does the operator have a plan that includes a schedule for implementing the program?
6. Does the program include requirements for updating responsibilities as organizational changes are made?
II Program Implementation: Has the public awareness plan been implemented and documented according to the written plan?
1. Is the program updated and current with any significant organizational or major new pipeline system changes that may have been made?
2. Are personnel assigned responsibilities in the written program aware of their responsibilities and have management support (budget and resources) for carrying out their responsibilities on the program?
3. Has the program implementation been properly and adequately documented?
4. Have all required elements of the program plan been implemented in accordance with the written plan and schedule?
5. Does the operator have documentation of the results of evaluating the program for effectiveness?
6. Are the results of the evaluation of program effectiveness being used in a structured manner to improve the program or determine if supplemental actions (e.g. revised messages, additional delivery methods, increased frequency) in some locations?

E.3 Supplemental Information to Operators Conducting Surveys to Evaluate Effectiveness

E.3.1 Type of Survey—Surveys may be conducted in person, over the phone, or via mail questionnaires. Conducting them in person is more labor intensive and costly but yields the best result and the largest return. Mail surveys are least expensive but typically have only 10-20 percent of the forms returned, which raises questions about whether the results are representative. Incentives for completing mail surveys may improve participation. Telephone surveys are a good compromise for the modest size samples needed to draw broad conclusions, but any of the methodologies can be made to work.

E.3.2 Sample Size—Typically a survey is designed to reach a random number of the targeted stakeholder audience. A variation on the random sample when conducting surveys in person is a "cluster sample" in which a block may be chosen at random and then a cluster of several households on the block visited at the same time. That is a relatively efficient way to increase sample sizes and not sacrifice much in statistical validity. The telephone number for affected residents is typically not readily accessible to the operator, although a random survey in a designated zip code or geographic area may include questions on whether the respondent lives or works along the right-of-way (to ensure a sufficient number of the affected public is included in the survey). For conducting a survey in person, the operator can work with a random selection of homes or businesses drawn from aerial maps or simply by selecting segments at random to be visited near the right-of-way. Mail surveys might be sent to all in a census tract, all in a zip code, or sub-zip code area. Third-party experts in conducting surveys can readily assist, at least for the first time a survey is attempted.

E.3.3 Statistical Confidence—There is typically concern about being statistically reliable. Often this leads to needlessly expensive surveys when one really only needs to know the approximate percentage of the target group that has been reached and is knowledgeable.

In deciding sample size, one can keep in mind a simplification of a lot of statistical rules and tables:

> The statistical error associated with a random survey is approximated by $1/\sqrt{n}$,where n is the size of the sample. A sample of 100 gives an accuracy of approximately $\pm 1/\sqrt{100}$, or about 10 percent.

There are a number of detailed assumptions behind that approximation, which is more valid the larger the total population to be surveyed. For smaller populations, the sampling error is actually even smaller than that approximation. Very modest-size surveys can be used for evaluating pipeline safety for public awareness and still have statistical validity to support broad conclusions that, in turn, drive changes (as necessary) or support continuation (when supported) to the Public Awareness Program.

E.3.4 Content—Different sets of questions are needed for different audiences. There obviously would be a different set of questions asked of households along a pipeline versus those asked of excavators. The survey questionnaire should be clear, brief and pre-tested to increase the participation and minimize the cost. Operators should try to keep their questions the same over time so that trends can be evaluated. The questions can be yes/no, multiple choice, or open-ended. It is easier to analyze data from multiple choice or yes/no questions than open-ended questions; the latter require someone to read and interpret them, and then complete computer-readable tallies or do a tally by hand. A combination of both open-end and multiple-choice questions can be used. A survey can focus on only one program element or several elements and can measure the following with one or more of the selected stakeholder audiences:

- **Outreach:** Surveys can determine whether the audience received the public awareness communication.
- **Knowledge:** Surveys can also inquire about what the person would do hypothetically in certain situations, such as "If you observed a suspected leak in a pipeline, what would you do?"
- **Behavior:** In addition to knowledge and attitudes, surveys can be designed to inquire of actual behaviors; e.g., "Have you ever called to inquire about the location of a pipeline," "Have you ever been involved in any way with a pipeline break or spill," etc.

As a supplement to the baseline survey, the operator or operators working in collaboration or with trade associations may also include information about general attitudes about pipelines and knowledge of their role in delivering energy.

Some thought is needed as to whether it is better to get open-ended responses that do not prompt the respondent, to avoid bias. A short example: One might be tempted to ask, "What number would you call if you saw a break in a pipeline," but that question already assumes somebody would look up a number, which may be what you are trying to determine. A less biased question would be "what would you do if you saw a break in a pipeline?"

E.3.5 Implementation—An operator can:

- Develop and conduct a survey on its own system using internal or external expertise
- Select a survey format designed by external parties or an industry association
- Adapt surveys designed by others and conduct on its own systems, or
- Join with others in a regional survey.

E.4 Sample Survey

E.4.1 Survey Questions—The content of the questions on the survey should reflect the goals of the public education program. The wording of questions is critical.

Developing appropriate wording is more difficult than it may appear to be on the surface. It is easy to inadvertently build in biases or confuse the person being interviewed. The questionnaires should be tested before use. A focus group or small sample can be used for that purpose. If the wording is changed, the questions should be retested.

Preferably, the same wording would be used for a group of operators if not all of the industry, to achieve comparability and be able to compare statistics for the industry or a region. Individual operators should try to keep their questions the same over time so that trends can be evaluated.

Where possible, it is preferable to use multiple-choice questions rather than open-ended questions, because the former are easier to analyze objectively. A combination of both open-end and multiple-choice questions can be used. Negative answers or problems raised by respondents preferably should be followed up by a diagnostic question to understand the respondent's point of view better, and to get insight for making improvements.

In the tables below are two sample sets of survey questions—one for the general public near pipelines, the other for excavators. These lists of questions can be used as menus from which to choose if there is time only for a few questions. The asterisked questions are the most important.

The questions may refer to the respondent's experience in the past six months, year, or two years; generally one does not ask about information older than one year because of memory problems, except for dramatic events likely to be remembered.

E.4.2 Introduction—In administering a survey, there should be a brief introduction to set the stage. For example:

> "Our company [or insert company name association] believes it is important to get feedback from people (excavators) such as you about pipeline safety. We would like to ask you a few questions and would greatly appreciate your candid answers. The information on your particular response will be kept confidential. Let me start by asking ...."

E.4.3 Venues—Basically the same questions can be asked during a formal survey, whether undertaken by mail, telephone, or in person. They also can be used during customer contacts or as part of contacts with appropriate personnel from excavators.

Tables

Table E-2—Sample Survey Questions for Affected Public

Attribute Measured		Sample Questions (Asterisk * marks most important questions.)
Outreach	*1.	In the last year [or 2 years], have you seen or heard any information from [our company] relating to pipeline safety? *[Yes or No]* If yes: 1a. What was the source of the information (check all that apply): a. Written material (brochure, flyer, handout) b. Radio? c. TV? d. Newspaper ad or article? e. Face-to-face meeting? f. Posted information (e.g., on or near pipeline) g. Other: ________ 1b. About how many times did you see information on pipeline safety in the last year?________
Outreach	2.	Have you or has or anyone in your household ever tried to obtain information about pipeline safety in the last 12 months? *[Yes or No]* ________ 2a. If yes, where did you try? Check all that apply: a. Internet b. Call c. Letter d. Visit e. Other: ________
Knowledge	*3.	Do you live close to a petroleum or gas pipeline? *[Yes, No, do not know]* 3a. If yes, where is it (or how close are you to it)?________ ________
Knowledge	*4.	What would you do in the event you were first to see damage to a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: ________
Knowledge	5.	What would you do if you saw someone intentionally trying to damage a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: ________
Behavior	*6.	Have you ever called a pipeline operator, 911, or anyone else to report suspicious or worrisome activity near a pipeline? *[Yes or No]* 6a. If yes, what did you report: a. Break b. Product release c. Digging d. Other: ________

Table E-2—Sample Survey Questions for Affected Public (Continued)

Attribute Measured	Sample Questions (Asterisk * marks most important questions.)
Behavior	*7. Have you or has anyone in your household [or company if a business] ever encountered a damaged pipeline or product released from a pipeline? *[Yes or No]* If yes, what did you do? ______________________ ______________________ ______________________
Behavior	8. Have you ever passed information about pipeline safety to someone else? *[Yes or No]* If yes, what information and to whom: ______________________ ______________________ ______________________
Outcomes	9. Has anyone in your household or have nearby neighbors ever had any injuries or damage associated with a pipeline break or spill? *[Yes or No]* 9a. If yes, describe event. ______________________ ______________________ ______________________
Attitude	10. Do you agree or disagree that your local pipeline operator has been doing a good job of informing people like you about pipeline safety? a. Strongly agree b. Agree c. Disagree d. Strongly disagree If you disagree, why: ______________________ ______________________ ______________________

Table E-3—Sample Survey Questions for Excavators

The questions below could be worded for a specific operator or for any operator; some excavators may deal with more than one pipeline.

Outreach	*1.	In the last 12 months, have you been contacted or received written information from [local pipeline operator] regarding pipeline safety? *[Yes or No]* If yes, what was the source: a. Telephone call b. Mail c. Visit or in-person meeting d. E-mail e. Sign or billboard f. Other:____________
Outreach	2.	Have you received information from any other sources about pipeline safety? *[Yes or no]* 2a. If yes, which? ____________
Behavior	3.	Have you contacted [pipeline operator name] in the past year to inquire about the location of pipelines? *[Yes or no]* 3a. If yes, about how many times? ____________ 3b. If yes, how did you make the contact: a. Telephone b. E-mail c. Letter d. In-person e. Other: ____________
Behavior	*4.	How often would you say your operator checks whether a pipeline exists before digging in a new spot? a. Always b. Usually c. Sometimes d. Rarely or Never e. Don't know. 4a. If not always: why not? a. Didn't know where to get information b. Not necessary c. Didn't think about it d. Takes too much time e. Think we can tell where pipeline is on our own f. Other: ____________
Outreach	5.	How do you make sure that all the right people in the company get the information on whom to call before digging? That is, how do you disseminate the information? a. Post it b. Discuss in meetings c. E-mail d. Calls e. Put in company's written procedures f. Put in company newsletter g. Other: ____________
Outreach (Audience Size)	6.	About how many people in your company actually determine where to dig? ____________

Table E-3—Sample Survey Questions for Excavators (Continued)

		6a. What jobs do they have (e.g., excavator equipment operator; executive; operations boss; etc.): ______
Outreach		6b. How many of them probably have information on where to call before digging? a. All b. Most c. Some d. Few or None
Outcome	*7.	Has your company ever unexpectedly encountered a pipeline while digging? *[Yes or No]*
		7a. If yes, how often has this occurred? ______ Explain whether pipeline location was unknown and why. ______ ______ ______
		7b. If yes, how many were "close calls"? ______
		7c. How many resulted in damage: ______

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am ______________________________representing ______________________________

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have an oil or gas pipeline running through your community? _____(Y/N)
If not yes, tell them. [Reviewers: Should we also ask if they know where it is?]

2. Do you know the name of your local pipeline operator? ________ (Y/N)

2a. If yes, who? ____
[This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding pipeline safety in the last 12 months?
___________ (Y/N)

3a. If yes, about how many? ____________

4. Before today, about when was your last contact with someone from the pipeline industry related to pipeline safety? ______________________ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call in the pipeline company if there is an incident or you need more information? ___________(Y/N)

6. Have you heard of the Office of Pipeline Safety in the U. S. Department of Transportation?
_________ (Y/N)

7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a pipeline? _______ (Y/N)

7a. If yes, what are they? ____

8. Are you familiar with the one-call line? _________ (Y/N)
(If no, they should be informed about it.)

9. How would you rate the adequacy of information you have about pipeline safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
   a. About right? ________
   b. Too much? ______
   c. Not enough? ______

[This question is essentially a self-assessment of knowledge for a measure such as "percent of local officials who felt they needed more information about pipeline safety."]

Behavior

10. Does your community have an emergency response plan to deal with a pipeline break (regard less of whether intentional or accidental)? _______(Y/N)

Outcome

11. Are you aware of any pipeline breaks that occurred in your community in the last 10 years?
____________ (Y/N)

11a. If yes, how many? ________

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines (Continued)

11b. What were they? ____
[The interviewer should be prepared to tell the local official the correct answer.]

12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding pipeline safety? __________ (Y/N)

12a. If yes, what was it? ____

13. Overall, do you feel the pipeline industry has an adequate public safety awareness program?
 a. Definitely yes ________
 b. Pretty much so _______
 c. Not sure ____________
 d. Don’t know _________
 e. Probably not ________
 f. Definitely not _______

[This is an overall perception of their awareness program. The operatory could use for measures such as “percent of local governments who rated the overall program as definitely or probably adequate.”]

Table E-4.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge	1.	Do you know where the nearest oil or gas pipeline is in or near your community? ______(Y/N) [If not, tell them after the interview.]
	2.	Do you know the name of your local pipeline operator? ________ (Y/N)
		15a. If yes, who? ____
	3.	Do you know who to call in the pipeline company if there is an incident, or if you need more information? _________(Y/N)
Outreach	4.	Have you seen, heard, or received any information regarding pipeline safety in any media in the last year? ________ (Y/N)
		17a. If yes, do you recall what? ____________________________________
	5.	Have you or anyone else in your department to your knowledge met with any representatives of the pipeline company to discuss pipeline safety within the last 12 months, prior to today? ______________(Y/N)
		18a. If yes, when?_________________________
		18b. With whom? ____
Behavior	6.	Do you have a response plan or SOPs for responding to a pipeline incident, such as a break? ___________ (Y/N)
	7.	Have you done any practical training to deal with a break? ____________(Y/N)
Outcome	8.	Do you know if there were any pipeline incidents within the last ten years in your community? _________ (Y/N)
		8a. If yes, about when? ____________
		8b. What was the incident? ____
		8c. Did the department respond? ________(Y/N)
		8d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.] ____ ____ ____ ____

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am ____________________________representing ____________________________

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have natural gas pipelines running through your community? _____(Y/N)
2. Do you know the name of your local natural gas company? ________ (Y/N)

   2a. If yes, who? ____
   [This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding natural gas safety in the last 12 months? ___________ (Y/N)

   3a. If yes, about how many? ___________

4. Before today, about when was your last contact with someone from the natural gas industry related to pipeline safety? _______________ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call the natural gas company if there is an incident or you need more information? ___________(Y/N)
6. Do you know who regulates the natural gas company in this community? _________ (Y/N) (If no, they should be informed about it.)
7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a natural gas pipeline? _________ (Y/N)

   7a. If yes, what are they? ____

8. Are you familiar with the one-call line? _________ (Y/N) (If no, they should be informed about it.)
9. How would you rate the adequacy of information you have about natural gas safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
   a. About right? ________
   b. Too much? ______
   c. Not enough? ______

   [This question is essentially a self-assessment of knowledge for a measure such as "percent of local officials who felt they needed more information about pipeline safety."]

Behavior

10. Does your community have an emergency response plan to deal with a natural gas leak (regardless of whether intentional or accidental)? _______(Y/N)

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies (Continued)

Outcome

11. Are you aware of any pipeline leaks that occurred in your community in the last 2 years? ____________ (Y/N)

    11a. If yes, how many? ________

    11b. What were they? ____
    [The interviewer should be prepared to tell the local official the correct answer.]

12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding natural gas safety? __________ (Y/N)

    12a. If yes, what was it? ____

13. Overall, do you feel the natural gas industry has an adequate public safety awareness program?
    a. Definitely yes _______
    b. Pretty much so ______
    c. Not sure ___________
    d. Don't know ________
    e. Probably not _______
    f. Definitely not ______

    [This is an overall perception of their awareness program. Could use for measures such as "percent of local governments who rated the overall program as definitely or probably adequate."]

Table E-5.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

First Responders/Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge

1. Do you have natural gas pipelines running through your community?? ______(Y/N)
   [If not, tell them after the interview.]
2. Do you know the name of your local natural gas company? ________ (Y/N)

   15a. If yes, who? ______________________________

3. Do you know how to contact the local natural gas company if there is an incident, or if you need more information? __________(Y/N)

Outreach

4. Have you seen, heard, or received any information regarding natural gas safety in any media in the last year? ____________ (Y/N)

   17a. If yes, do you recall what? ______________________

5. Have you or anyone else in your department to your knowledge met with any representatives of the natural gas company to discuss pipeline safety within the last 12 months, prior to today? ______________(Y/N)

   18a. If yes, when?_____________

   18b. With whom? _________________________

Behavior

6. Do you have a response plan or SOPs for responding to a natural gas incident, such as a leak? ______ (Y/N)
7. Have you done any practical training to deal with a leak? ____________(Y/N)
8. Do you feel reasonably well prepared to deal with a natural gas leak, should one occur in your community? ___________(Y/N) If not, in what areas are there deficiencies? (Check all that apply.)
   a. Training ______
   b. Special Equipment _____
   c. Knowledge about leaks _____
   d. Inherent dangers _____
   e. Other: (Write in.)______________________________
9. If you heard a report of a natural gas leak right now, what actions would you or your department take? [Write in the steps; someone should grade the responses to get a sense of whether there has been adequate training or preparation, or if the respondent just mentioned general procedures applicable to any kind of incident.]

   ____

   ____

Outcome

10. Do you know if there were any natural gas leaks within the last two years in your community? _________ (Y/N)

    10a. If yes, about when? ____________

    10b. What was the incident? _________________________

    10c. Did the department respond? ________(Y/N)

    10d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.] ______________________

    ____

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UG 435 / UG 411

NW Natural

Exhibit of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1902

June 6, 2022

CB Comments

Stakeholders	Methods	Tactic / Message	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Affected Public	**Media / PR**													
	Media - Television/Cable	Smell. Go. Let us know. New spot in spring 2021	■	■	■	■	■	■	■	■	■	■	■	■
	Media - Digital	Smell. Go. Let us know	■	■	■	■	■	■	■	■	■	■	■	■
	Media - Directories	24-hour Emergency Number	■	■	■	■	■	■	■	■	■	■	■	■
	Media - Spanish radio	811 Spanish - Call before you dig/¡Llame al 811!				■	■							
	PR - Letters to editors _ CAMs	811 - Call before you dig			■									
	PR - Press release	811 - Call before you dig			■									
	PR - Press release	Earthquake Preparedness/Great Shakeout									■			
	PR - Media	Media on-call pager 24/7	■	■	■	■	■	■	■	■	■	■	■	■
	Community	Dozer Days (WA)- TBD					■							
	Community	PIO Presentations over Zoom as requested	■	■	■	■	■	■	■	■	■	■	■	■
	Community	Safety/Emergency Preparedness Fairs (Virtual)												
	Community	Gas Safety Community Presentation Kit	■	■	■	■	■	■	■	■	■	■	■	■
	Training	Incident Command Team	■	■	■	■	■	■	■	■	■	■	■	■
Affected Public	**Social media**													
	Twitter/FB/IG	Smell. Go. Let us know	■											
	Twitter/FB/IG	Meter tampering/gas theft		■										
	Twitter/FB/IG	811			■									
	Twitter/FB/IG	Meter encroachment				■								
	Twitter/FB/IG	Grilling safety					■							
	Twitter/FB/IG	Equipment safety inspection						■						
	Twitter/FB/IG	Call Before You Clear							■					
	Twitter/FB/IG	Safety app								■				
	Twitter/FB/IG	Earthquake Preparedness/Great Shakeout									■			
	Twitter/FB/IG	Kitchen safety										■		
	Twitter/FB/IG	CO Awareness											■	
	Twitter/FB/IG	Fireplace safety												■
Noted by Mailing	**Mailings**													
	Emergency Officials (Fire and Police)	EO Bro, Pipeline Bro, Letter, Survey						■	■					
	Multi-Family (Tenants)	Gen Bro, Pipeline Bro, Letter, Survey						■	■					
	Excavators/Builders/Land Dev.	Flyer, Pipeline Bro, Eng/Span Letter, Survey						■	■					
	Floating Home	Letter						■	■					
	Public Officials	Flyer, Pipeline Bro, Letter, Survey						■	■					
	HCA/ROW (Along transmission line)	Custom Bro, Pipeline Bro, Sticker, Eng/Span letter, Survey						■	■					
	Call Before You Clear	Custom Bro, letter, door hanger						■	■					
	Call Before You Clear (Plumber)	Letter, flier						■	■					
LDC Customers	**Bill Inserts**													
	Brochure	Customer rights and responsibilities (Oregon residential, Washington residential, Oregon and Washington non-residential)					■							
	Brochure	Safety General										■		
	Brochure	Safety General for industrial and large-commercial customers										■		
	Brochure	Houseline maintenance												■
	Comfort Zone Newsletter	Smell. Go. Let us know			■									
	Comfort Zone Newsletter	811			■									
	Comfort Zone Newsletter	Cooking with gas/NEW: Indoor Air Quality			■									
	Comfort Zone Newsletter	Meter safety					■							
	Comfort Zone Newsletter	Equipment Inspection							■					
	Comfort Zone Newsletter	Earthquake Preparedness									■			
	Comfort Zone Newsletter	CO Awareness											■	
LDC Customers	**Email newsletter (e-Comfort Zone)**													
	e-Comfort Zone Newsletter	Smell. Go. Let us know	■											
	e-Comfort Zone Newsletter	Meter tampering/gas theft		■										
	e-Comfort Zone Newsletter	811			■									
	e-Comfort Zone Newsletter	Meter encroachment				■								
	e-Comfort Zone Newsletter	NEW: School safety program				■								
	e-Comfort Zone Newsletter	Grilling safety					■							
	e-Comfort Zone Newsletter	Equipment safety inspection						■						
	e-Comfort Zone Newsletter	Call Before You Clear							■					
	e-Comfort Zone Newsletter	Safety app								■				
	e-Comfort Zone Newsletter	Earthquake Preparedness									■			
	e-Comfort Zone Newsletter	Kitchen safety/NEW: indoor air quality										■		
	e-Comfort Zone Newsletter	CO Awareness											■	
	e-Comfort Zone Newsletter	Fireplace safety												■
LDC Customers	**Safety app**													
	Safety app topic	Smell. Go. Let us know (2 posts)	■											
	Safety app topic	Meter tampering/gas theft (2 posts)		■										
	Safety app topic	811 (2 posts)			■									
	Safety app topic	Meter encroachment (2 posts)				■								
	Safety app topic	Grilling safety (2 posts)					■							
	Safety app topic	Equipment safety inspection (2 posts)						■						
	Safety app topic	Call Before You Clear (2 posts)							■					
	Safety app topic	Safety app (2 posts)								■				
	Safety app topic	Earthquake Preparedness/Great Shakeout (2 posts)									■			
	Safety app topic	Kitchen safety/NEW: indoor air quality (2 posts)										■		
	Safety app topic	CO Awareness (2 posts)											■	
	Safety app topic	Fireplace safety (2 posts)												■
LDC customers	**On Hold Message**													
	Message	Smell. Go. Let us Know	■	■										
	Message	811			■	■					■	■		
	Message	Safety app					■	■						
	Message	Emergency Preparedness							■	■				
	Message	CO Awareness											■	■
All stakeholders	**Website**													
	Marquee	Safety tips and innovation	■	■										
		Spring safety			■	■								
		Safety app					■	■						
		Grilling safety							■	■				
		Fall safety									■	■		
		CO awareness											■	■
	Web touts	Carbon monoxide safety	■											
		Houseline maintenance	■											
		Meter tampering/gas theft		■										
		Call 811 (spring projects)			■									
		Safety app				■								
		Meter access/encroachment					■							
		Equipment safety inspection						■						
		Call Before You Clear							■					
		Call 811 (fall projects)								■				
		Earthquake Preparedness									■			
		Smell. Go. Let Us Know.										■		
		Cooking safety/NEW: indoor air quality											■	
		Pipeline safety												■
LDC customers	**New Customer Welcome Packets**													
	Brochures	General Safety, Houseline Maintenance	■	■	■	■	■	■	■	■	■	■	■	■
Emergency Officials	**Training/Personal Contact**													
	Police/Fire Departments and Utilities	Training (in-person)	■	■	■	■	■	■	■	■	■	■	■	■
	Fire Departments	Training (video)	■	■	■	■	■	■	■	■	■	■	■	■
School Program	Gradeschools	Teacher/student packets/website		■	■	■	■				■	■	■	■

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Reply Testimony of Amanda E. Faulk

COVID-19 DEFERRAL
EXHIBIT 2000

June 6, 2022

EXHIBIT 2000 – REPLY TESTIMONY – COVID-19 DEFERRAL

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Amanda Faulk. I am the General Accounting Senior Manager for NW Natural, responsible for the day-to-day operations of the accounting department. I oversee the planning, recording, compliance, and analysis of general and operational accounting and serve as the lead on various interdepartmental and intracompany projects including shared services management and accounting for new or unusual events. I also oversee the Sarbanes-Oxley ("SOX") compliance department.

Q. Please describe your education and employment background.

A. I graduated from Oregon State University with bachelor's degrees in Accountancy and Business Administration-Finance. I am a licensed Certified Public Accountant in the State of Oregon. In 2017, I received a Certificate in Utility Management from the Atkinson School of Management at Willamette University. I started at NW Natural in 2013, overseeing the SOX Compliance Program, and in 2015 I took on additional general and operational accounting manager duties. Before joining NW Natural in 2013, I worked in the audit practice of PricewaterhouseCoopers, LLP for six years.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to testimony filed on April 22, 2022, by the Public Utility Commission of Oregon ("Commission") Staff ("Staff") related to the Company's COVID-19 deferral. I will respond to issues presented in the testimony of Staff witnesses Curtis Dlouhy, John Fox, and Steve Storm (Staff/1500).

Q. Please summarize your testimony.

A. In my testimony, I first address Staff's proposal to amortize the COVID-19 deferral over a two-year period beginning on November 1, 2022. I then address Staff's proposed adjustments to the COVID-19 deferral and how the Company calculated direct cost savings resulting from COVID-19.

Q. Are there other issues related to the COVID-19 deferral that are being addressed by other Company witnesses?

A. Yes, the Reply Testimony of Kyle Walker and Robert Wyman (NW Natural/2300, Walker-Wyman) addresses Staff's proposed rate spread for the COVID-19 deferral and the Company's response to Staff's proposal to establish an earnings test for the deferral set at 50 basis points under the Company's authorized return on equity.

II. AMORTIZING THE COVID-19 DEFERRAL

Q. What is Staff's proposal regarding the amortization of the Company's COVID-19 deferral?

A. Staff proposes that NW Natural begin amortizing the COVID-19 deferral over a two-year period as a temporary increment in the Purchased Gas Adjustment (PGA) effective November 1, 2022.[1] NW Natural would recover approximately $5.8

[1] Staff/1500, Dlouhy-Fox-Storm/16-17.

million annually, which represents the total amount in the deferral through 2021, as well as all accrued interest at the stipulated rate in Order No. 20-401.[2]

Q. Has the Company previously proposed to begin amortization of its COVID-19 deferral?

A. No. In its initial rate case filing, the Company noted that it would seek to amortize the deferral at a later date in an effort to mitigate rate impacts of this proceeding.[3]

Q. Does the Company oppose Staff's proposal to amortize the COVID-19 deferral over a two-year period beginning on November 1, 2022?

A. No. While the Company is still mindful of the overall rate impacts of this proceeding, it does not oppose Staff's proposal.

III. PROPOSED ADJUSTMENTS TO COVID-19 DEFERRAL

Q. What is the balance of the Company's COVID-19 deferral?

A. As of December 31, 2021, the balance of the Company's COVID-19 deferral allocated to Oregon is $10,675,512.

Q. What costs and savings are included in the COVID-19 deferral?

A. NW Natural, other Oregon utilities, Staff, and stakeholders entered into a Stipulated Agreement, which the Commission subsequently approved in November 2020,[4] that included the following costs and savings in the COVID-19 deferral:

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[2] *Id.*

[3] NW Natural/100, Anderson-Kravitz/7.

[4] *In the Matter of Public Utility Commission of Oregon, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket UM 2114, Order No. 20-401 (Nov. 5, 2020).

- Direct costs for reasonable measures taken in response to the COVID-19 pandemic net of credits, payments, direct cost savings, or other benefits.
- Late payment fees not assessed (not to exceed the amount of late payment fees included in the last general rate case).
- Bad debt expense above baseline, as determined by the Company's last general rate proceeding.
- Forgone reconnection charges and field visits that do not result in disconnection and field connection charges not assessed to customers.
- Forgone reconnection charges for customers disconnected from system prior to March 13, 2020.
- COVID-19 Arrearage Management Program (AMP).

Q. Does Staff propose any adjustments to the COVID-19 deferral?

A. Yes. Staff proposes a $304,885 reduction to the Company's $10,675,512 deferral balance as of December 31, 2021. Specifically, Staff proposes to:

- Reduce the Company's 2020 and 2021 bad debt expense by $19,082 in 2020 and $53,598 in 2021.[5]
- Reduce the late payment fees not assessed by $141,948 in 2020 and $90,258 in 2021.[6]

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[5] Staff/1500, Dlouhy-Fox-Storm/13.

[6] *Id.* at 14.

- Move the $157,955 in costs savings associated with Employee Expenses from 2021 to 2020.[7]

Q. Please explain Staff's adjustment for bad debt expense.

A. Staff compared the bad debt expense in the Company's January 28, 2022 filing in docket RG 90, which itemizes utility costs, savings, and benefits resulting from COVID-19, with the Company's response to OPUC Staff DR 416, in which bad debt expense was also calculated. Staff stated it reduced bad debt expense by $19,082 in 2020 and $53,598 in 2021 in order "to conform to the Company's response to Staff DR No. 416 Attachments 1 and 2."[8]

Q. Does the Company agree with Staff's proposed adjustment to bad debt expense?

A. No. The difference that Staff notes between the Company's response to Staff DR No. 416 Attachments 1 and 2 and the total bad debt expense deferral reported in RG 90 is the calculated accrued interest of $72,679 as of December 31, 2021.[9] Order No. 20-401 specifically allows the Company to defer, for later recovery, the accrued interest associated with the Company's bad debt expense. Therefore, Staff's proposed adjustment should not be adopted. Exhibit NW Natural/2001, Faulk/1 provides detail on this reconciliation.

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[7] *Id.* at 14-15.

[8] *Id.* at 13.

[9] See Exhibit NW Natural/2001, Faulk/2 for detail on the reconciliation of the variance between the Company's response to DR No. 416, Attachments 1 and 2, and RG 90.

Q. Please explain how Order No. 20-401 allows the Company to accrue interest on the COVID-19 deferral.

A. Order No. 20-401 states that "the deferral balance, whether being accrued (pre-prudence), found to be prudent in an annual prudence review (pre-amortization), or being amortized, shall accrue the same interest rate, equal to the blended Treasury rate plus 100 basis points. To the extent the amortization of the deferral is more than two years for a Utility, that Utility may request that the Commission authorize a larger basis point spread." Additionally, Staff, itself, recognizes and proposes amortization of the total COVID-19 deferral including any accrued interest at the stipulated interest rate in Order No. 20-401, consistent with the Company's calculated accrued interest.[10]

Q. Did the Company calculate accrued interest in accordance with Order 20-401?

A. Yes. The Company used the annual verified Modified Blended Treasury (MBT) rate plus 100 basis points in accordance with Order No. 20-401 as follows:

Accrued Interest	2020	2021
MBT	2.63%	1.24%
Plus 100 bps	1.00%	1.00%
Deferral Interest Rate	**3.63%**	**2.24%**

Interest was booked to the deferral accounts for the entire deferral period upon receipt of Order No. 20-401.

[10] Staff/1500, Dlouhy-Fox-Storm/2.

Q. Were there any data requests provided by NW Natural to Staff that included both the underlying calculated deferral amount and the interest?

A. Yes. The calculated interest for the COVID-19 deferral was included in the Company's response to Staff DR 413.[11]

Q. Did the Company's RG 90 quarterly filings include interest on bad debt expense?

A. Yes. In 2021, Staff requested that the Company begin disaggregating the Bad Debt Expense by customer class, resulting in interest also being disaggregated.

Q. Please explain Staff's proposed adjustment for late payment fees.

A. Staff proposes to lower the deferral balance's late payment fee expense by $141,948 in 2020 and $90,258 in 2021. Similar to bad debt expense above, Staff compared the late payment fee expense in the Company's January 28, 2022 filing in docket RG 90, which itemizes utility costs, savings, and benefits resulting from COVID-19, with the Company's response to Staff DR 417,[12] in which late payment fee expense was also calculated. Staff lowered late payment fee expense to conform to the Company's response to Staff DR 417 and also eliminated any late payment expense that it claims was included in the deferral prior to it being filed on March 24, 2020.[13]

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[11] Staff/1501, Dlouhy-Fox-Storm.

[12] *Id.*

[13] Staff/1500, Dlouhy-Fox-Storm/13-14.

Q. Please explain why there is a difference between the Company's January 28, 2022 filing in docket RG 90, and the Company's response to Staff DR 417.

A. The difference between Attachment 1 of the Company's response to Staff DR 417 and the Company's January 28, 2022 filing in RG 90 is $113,673. Of this amount, $68,610 is due to accrued interest as of December 31, 2021 that the Company did not include in its response to Staff DR 417. However, as explained above, NW Natural is allowed to defer accrued interest per Order 20-401. The remaining difference of $45,062 represents an adjustment made in January 2021 to the November and December 2020 late fees that reflects a rate increase effective November 1, 2020.[14] This adjustment was not included in the response to Staff DR. 417. Exhibit NW Natural/2001, Faulk/1-2 provide further detail on the reconciliation of these variances.

Q. Does the Company agree with Staff's proposed adjustment for these differences between Attachment 1 of the Company's response to Staff DR 417 and the Company's January 28, 2022 filing in RG 90?

A. No. Because the differences between Attachment 1 of the Company's response to Staff DR 417 and the Company's January 28, 2022 filing in RG 90 are due to accrued interest that the Company is permitted to defer under Order No. 20-401 and a Commission-approved rate increase, the Company does not believe that an adjustment that reflects either difference is warranted.

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[14] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket UG 388, Order No. 20-364 (Oct. 16, 2020).

Q. Is Staff correct that the Company is seeking to defer late payments not assessed prior to the Company filing its COVID-19 deferral on March 24, 2020?

A. No. The Company merely followed the Stipulated Agreement in determining the amount of late payment fees not assessed. The Stipulated Agreement caps the amount of late payment fees not assessed at the annual amount from the Company's last general rate case. Specifically, the Stipulated Agreement stated that "the amount of deferred late fees recorded in any year, including any late payment fees that were assessed prior to suspension in that year shall not exceed the amount of late payment fees included in the Commission's final order from the Utility's last general rate case."[15] As a result, the Company created a methodology to book the monthly accounting entries for the late payment fees not assessed. Because the Stipulated Agreement uses an annual amount from the Company's prior general rate case, the Company developed an accounting methodology that estimated how that annual amount would be allocated on a monthly basis and compared those amounts to the total late payment fees incurred for the year in the deferral calculations.

The Company believes this treatment is consistent with the Stipulated Agreement, which specifies that late payment fees prior to filing the COVID-19 deferral should be considered in the calculation to ensure the total actual late fees

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[15] *In the Matter of Public Utility Commission of Oregon, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket UM 2114, Order No. 20-401, Appendix A, at 20 (November 5, 2020).

billed and the deferral for the year does not exceed the amount in the last rate case.[16]

Q. Do you believe that Staff's adjustment is warranted?

A. No. The Company's calculations were consistent with the Stipulated Agreement and alternative methodologies would either not have resulted in any change or increased the amount deferred. For instance, if the monthly late fee revenue actuals were compared against the general rate case straight-lined each month, the 2020 total late payment deferral would be the same amount. If, however, there were an adjustment for January through March, as proposed by Staff, the adjusted late fee deferral would have actually increased. It would have been $1,414,715 instead of the $1,231,072 that NW Natural actually deferred. Exhibit NW Natural/2001, Faulk/3 provides detail on these calculations.

Q. Please explain Staff's proposed adjustment to reclass $157,955 of cost savings from 2021 to 2020 for the purposes of amortization.

A. While Staff finds no issue with the total amount included in the cost savings category of the Company's COVID-19 deferral, it does not believe that the timing is correct. In its most recent RG 90 filing, the Company does not list any cost savings under the "Employee Expenses: education and refreshments" category until the first quarter of 2021. Staff claims that this should be re-classed to 2020 based on the Company's response to Staff DR 414.[17]

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[16] *Id*.

[17] Staff/1500, Dlouhy-Fox-Storm/14-15.

Q. Do you agree that these savings should be re-classed to 2020?

A. Yes. Staff is correct that the $157,955 of cost savings occurred in 2020. The timing difference between the Company's response to Staff's DR 414 and its most recent RG 90 filing is because the additional 2020 cost savings was an out-of-period adjustment that was not identified or recorded until 2021.

Q. Why did the Company make an out-of-period adjustment?

A. The Company made an out-of-period adjustment because it continued to evaluate its operational savings for completeness. The cost savings category referenced above was identified after responding to data requests in the COVID-19 deferral docket (UM 2068) and discussions with peer utilities.

Q. Does Staff have any other concerns regarding COVID-19 savings?

A. No. Staff "finds no issue with the total amount included in the Cost Savings category in the Company's COVID-19 deferral."[18] Nonetheless, in its Direct Testimony, Staff stated that, by its very nature, it is harder to verify direct cost savings, as opposed to "benefits received directly from a government agency."[19]

Q. Please describe the COVID-19 cost savings identified and recorded by the Company.

A. The Company identified its internal cost savings as those areas that were directly impacted by COVID-19 restrictions and out of the Company's control. The categories the Company evaluated and were impacted from COVID-19 were

[18] *Id.* at 14.

[19] *Id.* at 10.

employee expenses related to travel and training: Meals and Entertainment, Refreshments, Business and Conference Travel, and Education. These categories are consistent with our peer utilities.

Q. How were the COVID-19 cost savings calculated and recorded by the Company?

A. Consistent with the "baseline" general rate case methodology noted in the Stipulated Agreement and used in the direct cost categories such as bad debt expense, the Company used its prior rate case recoverable amounts in these categories noted to calculate the savings realized against the actuals incurred throughout the year.

Q. Do you agree with Staff's conclusion that there is "no issue with the total amount included in the Cost Savings category in the Company's COVID-19 deferral"?

A. Yes. As described above, the Company calculated its cost savings consistent with the Stipulated Agreement adopted in Order No. 20-401.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Amanda E. Faulk

COVID-19 DEFERRAL
EXHIBIT 2001

June 6, 2022

EXHIBIT 2001 – COVID-19 DEFERRAL

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COVID - Proposed Staff/1500 adjustment reconciliation	Amount
Total proposed adjustment	**304,885**
Late Fees Interest	68,610
Late Fees Jan-Mar 2020 monthly vs. annual	163,595
Uncollectibles Interest	72,679
Total reconciling items	**304,885**
Difference	0

Bad Debt Expense - COVID Deferral

Year	DR 416 - Total Calculated Bad Debt Expense Above Baseline	RG 90 - Total Bad Debt Expense Above Baseline Deferral	Difference	RG 90 - Interest	Interest Difference	Comment
2020	2,074,680	2,093,761	19,081	22,789	3,708	immaterial - 2020 deferral under recorded from calculated
2021	(187,682)	(134,084)	53,598	53,598	0	
Total	**1,886,998**	**1,959,677**	**72,679**	**76,388**	**3,708**	immaterial - 2020 deferral under recorded from calculated

Unbilled Late Fees - COVID Deferral

Year	DR 417 - Total Calculated Late Fees up to Baseline	RG 90 - Total Late Fees up to Baseline Deferral	Difference	DR 413 - Interest	Interest Difference	Comment
2020	1,231,071.85	1,254,487	23,415	23,415	0	
2021	1,173,020.39	1,263,278	90,258	45,195	(45,062)	November and December 2020 adjustment for UG 388 increase, refer to next tab
Total	**2,404,092**	**2,517,765**	**113,673**	**68,610**	**(45,062)**	

2021 Late Fee Charge Deferral Calculation **January 2021**

OREGON	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
OR Actual Billed	152,874												
OR UG 388	241,961	297,474	262,799	252,580	213,854	150,477	80,815	76,018	72,217	74,222	104,822	178,059	
Difference	**(89,087)**												(89,086.53)

YTD	(89,086.53)	
Recorded	-	
Amount to record	(89,086.53)	

Entry:

Dr 186431	(89,086.53)	(134,149.01)
Cr 487-06260	89,086.53	

Adjustment for November - December 2020 (From OR UGG 344 to OR UG 388)				
	Nov-20	Dec-20	Total	
OR Actual Billed	11	102,182	102,192	*See 2020 OR Late Fee Deferral tab for Original Data*
OR UG 388	104,822	178,059	282,881	*from above/OR UG 388*
Difference	**(104,811)**	**(75,877)**	**(180,688)**	***What Should Have Been Recorded***
OR Actual Billed	11	102,182	102,192	*See 2020 OR Late Fee Deferral tab for Original Data*
OR UG 344	88,422	149,396	237,818	*See 2020 OR Late Fee Deferral tab for Original Data*
Difference	**(88,412)**	**(47,214)**	**(135,626)**	***What Was Recorded in Nov & Dec 2020***
Adjustment to Record	**(16,399)**	**(28,663)**	**(45,062)**	**dr 186431**

Actual original 2020 Unbilled Late Fee deferral calculation - using the company's budgeted split of UG 344 across the year.

2020 Late Fee Charge Deferral Calculation **December 2020 - Original as listed for 2020**

OREGON	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
OR Actual Billed	266,454	287,781	116,876	(1,366)	(1,147)	(269)	(67)	(46)	(81)	(14)	11	102,182	770,312.45
OR UG 344 - budgeted	259,514	306,130	261,259	245,748	207,988	161,572	90,370	78,708	75,754	76,523	88,422	149,396	2,001,384.30
Difference	6,940	(18,349)	(144,383)	(247,115)	(209,135)	(161,840)	(90,437)	(78,754)	(75,835)	(76,537)	(88,412)	(47,214)	(1,231,071.85)
2020 YTD Deferral under UG 344	**(1,231,072)**												
With Staff's Jan, Feb, + 23days adjustment	**(1,112,539)**												

Original 2020 Unbilled Late Fee deferral calculation - using the straightline split of UG 344 across the year.

2020 Late Fee Charge Deferral Calculation **December 2020 - Original as listed for 2020**

OREGON	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
OR Actual Billed	266,454	287,781	116,876	(1,366)	(1,147)	(269)	(67)	(46)	(81)	(14)	11	102,182	770,312.45
OR UG 344 - Straight Line	166,782	166,782	166,782	166,782	166,782	166,782	166,782	166,782	166,782	166,782	166,782	166,782	2,001,384.30
Difference	99,671	120,999	(49,906)	(168,148)	(167,929)	(167,051)	(166,849)	(166,828)	(166,863)	(166,796)	(166,772)	(64,600)	(1,231,071.85)
2020 YTD Deferral under UG 344	**(1,231,072)**												
With Staff's Jan, Feb, + 23days adjustment	**(1,414,715)**												

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 435 / UG 411

NW Natural

Reply Testimony of Anna K. Chittum

LEXINGTON RNG PROJECT
EXHIBIT 2100

REDACTED

June 6, 2022

EXHIBIT 2100 – REPLY TESTIMONY– LEXINGTON RNG PROJECT

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I. INTRODUCTION AND SUMMARY

Q. Are you the same Anna Chittum who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company ("NW Natural" or the "Company")?

A. Yes, I presented NW Natural/1100, Chittum.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to testimony filed on April 22, 2022, by the Public Utility Commission of Oregon Staff ("Staff"), the Alliance of Western Energy Consumers ("AWEC"), and the Coalition of Communities of Color, Sierra Club, Verde, Climate Solutions, Oregon Environmental Council, Columbia Riverkeeper, and Community Energy Project (collectively, the "Coalition") related to renewable natural gas ("RNG") in general, and more specifically, the Lexington RNG project, which the Company seeks recovery of in this proceeding. I will respond to issues presented in the testimony of the Coalition witness Nora Apter (Coalition/100), AWEC witness Bradley Mullins (AWEC/100), and Staff witness Matthew Muldoon (Staff/1700).

Q. Please summarize your testimony.

A. In my testimony, I respond to the Coalition's general concerns regarding the environmental attributes of RNG procured by the Company to date. This RNG includes both purchases from third parties that the Company is not seeking to recover in this proceeding, as well as the Lexington RNG project that the Company is seeking to recover.

Next, I provide an update on the Lexington RNG project, which has begun commercial operation and is currently producing RNG. I will also respond to an issue that AWEC raised in its Direct Testimony regarding distributions to the project's co-developer, BioCross. Other issues that AWEC raised concerning the revenue requirement and the rate spread of the Lexington RNG project are addressed in the Reply Testimony of Kyle Walker and Robert Wyman (NW Natural/2300, Walker-Wyman).

Finally, I will address several concerns that Staff expressed in its Direct Testimony regarding how NW Natural may seek to procure RNG in the future.

II. ENVIRONMENTAL ATTRIBUTES OF RNG

Q. Please explain why RNG is environmentally beneficial.

A. As I explained in my Direct Testimony, RNG is a resource produced from gases that are emitted during the breakdown of organic materials such as food, agricultural and forestry waste, wastewater, and landfill material. Decomposition of this material is already taking place organically and, if left unchecked, produces methane that would be emitted into the atmosphere. Instead of allowing these emissions to occur, the methane can be captured and conditioned to pipeline quality gas (RNG) where it can be used in existing appliances and equipment.[1]

[1] Per ORS 757.392(7), RNG also refers to "[h]ydrogen gas derived from renewable energy sources." Renewable energy sources are defined as "hydroelectric, geothermal, solar photovoltaic, wind, tidal, wave, biomass or biogas energy sources." This testimony primarily focuses on RNG produced from organic materials.

This process reduces greenhouse gas ("GHG") emissions while alleviating an existing waste problem.

Q. Is the procurement of RNG consistent with Oregon climate policy?

A. Yes. Executive Order 20-04, which establishes aggressive GHG reduction targets, states that "transitioning the traditional natural gas supply to renewable natural gas can significantly reduce GHG emissions."[2] Similarly, Senate Bill 98, which authorizes Oregon natural gas utilities to procure RNG, states: "Natural gas utilities can reduce emissions from the direct use of natural gas by procuring renewable natural gas and investing in renewable natural gas infrastructure."[3] Finally, the Climate Protection Program ("CPP") recently adopted by the Oregon Environmental Quality Council, which seeks to cap-and-reduce GHG emissions, also recognizes that RNG can be used in lieu of natural gas to lower emissions,[4] thereby helping Oregon natural gas utilities comply with the program.

Q. Given the environmental benefits, why does the Coalition question the Company's decision to pursue the procurement of RNG in general?

A. The Coalition states that its concerns with NW Natural's strategy to reduce GHG emissions through the procurement of RNG are: 1) the lack of an adequate RNG

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[2] "Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions, Executive Order No. 20-04, at 2, available at https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf

[3] ORS 757.390(2).

[4] See OAR 340-271-0110(4)(b)(B)(i).

supply, 2) unintended consequences of this strategy, 3) the cost of RNG, and 4) NW Natural's overly optimistic timeline.[5]

Q. How do you respond to the Coalition's contention that there is insufficient RNG available to meet the Company's acquisition goals?

A. The Coalition's argument that there is not sufficient RNG to meet NW Natural's RNG and GHG reduction targets is completely unfounded. The Coalition's claims rely solely on a study that was performed five years ago,[6] and was a much narrower look at the potential for RNG than is available today, given the major growth and maturation of the industry. The RNG industry in the United States is young but has shown significant growth over the last few years. Indeed, five years ago there were about 40 operating RNG projects, but project development has increased substantially in recent years. The number of RNG projects grew 33.5 percent just from 2020 to 2021 alone, and number over 230 projects operating today and another 108 under construction.[7] Numerous studies have identified the tremendous potential of RNG, including a recent study by ICF, which was also

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[5] Coalition/100, Apter/15.

[6] Coalition/100, Apter/15-16 (citing ICF, Energy Design Principles for Renewable Natural Gas, at 10, Ex. 5 (2017), available at https://www.icf.com/-/media/files/icf/white-paper/2017/icf_whitepaper_design_principles.pdf

[7] *See* U.S. Dept. of Energy, Argonne National Laboratory, Turning waste to energy: tracking renewable natural gas transportation projects, *available at*: https://www.anl.gov/article/turning-waste-to-energy-tracking-renewable-natural-gas-transportation-projects;
New Assessment Documents Expansion of US Renewable Natural Gas Industry, available at: https://finance.yahoo.com/news/assessment-documents-expansion-us-renewable-233000175.html?guccounter=1&guce_referrer=aHR0cHM6Ly9hbWVyaWNhbmJpb2dhc2NvdW5jaWwub3JnLw&guce_referrer_sig=AQAAAJlg2h2AIy7A5e20OedjqFqXbkfL6Z76RjTqw3XUxkqWL6P6lfxd9CHomOL7pBzx1dUTpCbDbJmHAv7DFmb1HkrsPcGHqxVZLKnMLBvU4cPQLgDAt17SmeAaR6uoRNNH6vpqzQCUhHlRL8c10-oL4WKfTzc6oHMwOiunNy0jSMqp

responsible for the 2017 study cited by the Coalition in its Direct Testimony. The more recent ICF study found that by 2050 the total potential for RNG in the country produced from organic sources is about 6,645 trillion btus/year, which is a large increase even from ICF's 2019 study that found the potential to be under 4,000 trillion btus/year by 2040 .[8] Additionally, the Coalition's Direct Testimony focuses only on RNG produced from organic sources, ignoring the fact that ORS 757.392(7) also defines RNG as "[h]ydrogen gas derived from renewable energy sources." By only focusing on one type of RNG, the Coalition's contention that there is a lack of supply is misleading. In fact, consistent with ORS 757.392(7), the recent ICF study identifies the potential for renewable hydrogen, which is essentially unlimited in terms of feedstocks.[9]

Q. How do you respond to the Coalition's argument that there will be unintended consequences with the Company procuring RNG?

A. The Coalition's argument that NW Natural will intentionally cause emissions to create RNG is wholly without merit. NW Natural is not acquiring RNG from purpose grown crops, and the Company has no intention of departing from that approach. For example, NW Natural's Lexington RNG project refines raw biogas, which is derived from the anaerobic digestion of food processing-based wastewater and other byproducts at the Tyson Fresh Meats beef packaging plant in Lexington,

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[8] *See* NW Natural/2101, Chittum/9.

[9] *Id.*

Nebraska, into RNG. This source of raw biogas predates NW Natural's involvement in the project and NW Natural is not the source of it.

Q. How do you respond to the Coalition's argument that RNG will be too expensive for the Company to procure?

A. Contrary to the Coalition's argument, the costs of CPP compliance, which include the acquisition of RNG, are manageable. The Reply Testimony of Kimberly Heiting and Ryan Bracken (NW Natural/1700, Heiting-Bracken) addresses this issue in detail, concluding that the projected overall customer bill impact of the CPP is reasonable.

In addition, ORS 757.396(5) limits the amount that the Company can spend on its RNG investments, unless the Commission otherwise approves. As I explained in my Direct Testimony, ORS 757.396(5) states that, absent Commission approval, a natural gas utility cannot make further investments in RNG if the difference between the total (or "all-in") levelized annual cost of the utility's RNG portfolio and the all-in levelized annual cost of the same quantity of conventional natural gas (i.e., the incremental cost of RNG) exceeds 5 percent of a natural gas utility's annual revenue requirement. The "all-in" cost reflects the total cost for a unit of natural gas, not just the gas commodity cost. In short, ORS 757.396 already provides the cost protection that the Coalition seeks and, because the Company is not exceeding this cap, it should not be an issue in this proceeding.

Q. Do you agree with the Coalition that NW Natural's timeline is overly optimistic?

A. No. NW Natural's preliminary modeling of how it will comply with the CPP in docket UM 2178 indicates that NW Natural will not exceed the ORS 757.396 volumetric targets until approximately 2030.[10] Given NW Natural's recent experience in the RNG market (both through its requests-for-proposals and its project development work), it is confident that it can meet these targets and eventually exceed them in order to comply with the CPP.

Q. Does the Coalition argue that the Company's acquisition of RNG is contrary to ORS 757.390-398 (i.e., Senate Bill 98)?

A. Yes. The Coalition argues that NW Natural's purchases of RNG, as well as its investment in the Lexington RNG project, is imprudent because it is contrary to Senate Bill 98 requirements.[11]

Q. What Senate Bill 98 requirements does the Coalition argue NW Natural fails to satisfy?

A. The Coalition argues that NW Natural is only purchasing the environmental attributes of RNG, known as renewable thermal credits ("RTCs"), to demonstrate

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[10] *In the Matter of Oregon Public Utility Commission Staff Natural Gas Fact-Finding Per Executive Order 20-04*, Docket UM 2178, NW Natural's Compliance Modeling Presentation – Second Update, at slide 43, available at: https://edocs.puc.state.or.us/efdocs/HAC/um2178hac10454.pdf

[11] Coalition/100, Apter/19-20.

that it is meeting Senate Bill 98 targets, and that the RNG is not being injected into a common carrier pipeline as required by OAR 860-150-0050(7).[12]

Q. With respect to the Lexington RNG project, is NW Natural only purchasing the environmental attributes?

A. No. As explained in my Direct Testimony, the Company is acquiring both the energy content of the RNG and the RTCs for the Lexington RNG project. More specifically, NW Natural is acquiring both the energy content of the gas and the RTCs through an affiliated subsidiary, Lexington Renewable Energy LLC. This is how virtually all RNG projects in the country market their RNG – by separately selling the attributes (often for clean transportation fuel programs, such as the Oregon Clean Fuels Program) and the energy content.

Q. After NW Natural acquires both the energy content of the RNG and the RTCs, what happens next?

A. NW Natural injects the gas into a common carrier pipeline (the Black Hills Energy pipeline system), as required by OAR 860-150-0050(7). As a common carrier pipeline, Black Hills uses its pipeline system in Nebraska to move the gas owned by third parties. Specifically, in this area of Nebraska, Black Hills Energy operates "a transmission and transportation utility" offering firm transportation service to third parties.[13] After NW Natural injects the RNG into the common carrier pipeline, it sells the energy content of the gas (without the environmental attribute) to a gas

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[12] *Id.*

[13] Black Hills Energy, Natural Gas Pipelines, available at: https://pipelines.blackhillsenergy.com/nebraska-gas

marketer in Nebraska that has transportation rights on the Black Hills pipeline system.

Q. With respect to NW Natural's purchases of RNG from third parties, is NW Natural only purchasing the RTCs, not the energy content of the gas?

A. Yes. Such purchases are permitted under Senate Bill 98 rules. While NW Natural is not seeking cost recovery of any RNG purchases from third parties in this proceeding, I feel that it is important to respond to the Coalition's assertions that these purchases are somehow not consistent with Senate Bill 98. Senate Bill 98 rules require that gas utilities deliver the environmental attributes of the RNG (the RTCs) to meet ORS 757.396(1) targets, but does not require physical delivery of the underlying gas. In its March 10, 2020 report on the Senate Bill 98 rules, Staff stated that the "rules establish a 'book-and-claim' accounting system, whereby RTCs and the associated attestations regarding environmental claims about the RNG the RTCs were originally associated with can be tracked electronically from the point in time when the RNG is injected into a common carrier pipeline, with no need to track the physical gas itself."[14] Staff concludes that the Senate Bill 98 rules do not require physical delivery of the RNG, but "instead specify how natural gas utilities must utilize RTCs, as well as what the utilities may not do with RTCs."[15]

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[14] *In the Matter of Rulemaking Regarding the 2019 Senate Bill 98 Renewable Natural Gas Programs*, Docket AR 632, Staff Report, at 7, available at: https://edocs.puc.state.or.us/efdocs/HAU/ar632hau151952.pdf

[15] *Id.*

In other words, the environmental attributes (the RTCs) are needed to meet ORS 757.396 targets, and the physical delivery of the energy content of the gas is not required. While there is a requirement that any RNG must be injected into a common carrier pipeline (and NW Natural ensures that such gas is injected into such a pipeline), there is, again, "no need to track the physical gas itself."[16] The Commission ultimately adopted Staff's recommendation that required RNG to be injected into a common carrier pipeline, and not require delivery of the physical gas.[17] The Commission has also already approved the inclusion of two RNG offtake agreements in NW Natural's Purchased Gas Adjustment where, again, the Company delivers the RTC (the environmental attributes) to its customers, but not the physical gas.[18]

Finally, it is important to underscore that similar programs that support and regulate renewable fuels, both in Oregon and elsewhere, rely on the environmental attributes of the renewable fuels being delivered to satisfy program requirements, not the energy content of the renewable fuels. The construct that the Commission adopted in Senate Bill 98 rulemaking is consistent with these established programs.

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[16] *Id.*

[17] OAR 860-150-0050(7).

[18] *In the Matter of Northwest Natural Gas Company, dba, NW Natural, Request for Amortization of Certain Deferred Accounts Related to Gas Costs, Schedules P, 162, 164*, Docket UG 432, Order No. 21-376 (Oct. 28, 2021).

Q. Despite being used by numerous state and federal programs, the Coalition calls this Commission-approved framework for procuring RNG "greenwashing."[19] How do you respond?

A. I disagree strongly that the Commission-approved framework for acquiring RNG is greenwashing. The approach has the support of the Oregon Department of Environmental Quality ("DEQ"), with the Commission stating that "DEQ noted that the flexibility of the approach helps the development of projects that would otherwise be uneconomic if physical delivery was required."[20] The Commission also stated that DEQ supported book-and-claim accounting, which "allows electronic tracking of RTCs as of injection into a common carrier pipeline, with no need to track the physical gas," and that "[t]he approach is consistent with how RNG is tracked in the Oregon Clean Fuels Program, as well as in the California Low Carbon Fuel Standard, and the federal Renewable Fuel Standard."[21] Far from being greenwashing, the Commission adopted a framework consistent with similar programs and with the full support of the DEQ. NW Natural has followed that framework in procuring RNG.

[19] Coalition/100, Apter/17-18.

[20] *In the Matter of Rulemaking Regarding the 2019 Senate Bill 98 Renewable Natural Gas Programs,* Docket AR 632, Order No. 20-227 at 5 (July 16, 2020).

[21] *Id.*

Q. Why do you believe that the Commission-approved framework for RNG procurements makes sense?

A. As I explain above, the environmental benefit of RNG is that it prevents emissions associated with the decomposition of organic material from otherwise occurring by instead capturing and conditioning those emissions into pipeline quality gas (RNG). Delivering the energy content of that gas to Oregon customers or customers in another state neither increases nor decreases the environmental benefits of RNG. Rather the environmental benefit is tied to the emissions that were prevented from occurring as a result of the RNG production process, the output of which displaces conventional natural gas when injected into a common carrier pipeline. GHG reductions that occur in Nebraska are every bit as valuable to Oregonians (and the planet more broadly) as GHG reductions that occur in Oregon. Through the Commission-approved RNG framework, which requires that NW Natural retire RTCs on behalf of its Oregon customers, these emissions reductions are appropriately credited to the Company's customers, which ultimately bear the cost of the Company's RNG acquisitions.

Q. The Coalition argues that the Lexington RNG project and the Company's purchases of RNG from third parties do not qualify under the CPP. How do you respond?

A. First, NW Natural made the decision to pursue the Lexington RNG project in late 2020. At that time, the CPP was not developed and, in fact, final CPP rules would not be approved until late December 2021 when the Lexington RNG project was nearly complete. Nonetheless, at the time NW Natural made the decision to pursue the project, it believed that the CPP would be consistent with the Commission's Senate Bill 98 rules based on the DEQ's support of book-and-claim accounting and its use in another DEQ program (Oregon Clean Fuels Program), as well as the California Low Carbon Fuel Standard and the federal Renewable Fuel Standard (see above).[22] Given the need to decarbonize as quickly as possible, NW Natural did not believe it was advisable to wait until the CPP was finished and, moreover, it would have lost the opportunity to pursue the project if it had attempted to wait an additional year before committing to it.

Second, the CPP, as adopted by the Oregon Environmental Quality Commission ("EQC"), is consistent with the Commission's Senate Bill 98 rules and the Lexington RNG project satisfies the requirements of both programs, despite the Coalition's arguments to the contrary.

During the CPP rulemaking process, NW Natural asked the DEQ to clarify "that RNG purchased to comply with the CPP does not have to be tracked to the specific end user of where the RNG is delivered [and that this] would align the book-and-claim accounting of multiple other federal and state programs, including programs in Oregon."[23] In the EQC Staff Report, which accompanied the final rules, DEQ accurately summarized NW Natural's concern, stating that the Company wants to "allow for book-and-claim accounting of RNG or RNG procured

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[22] *In the Matter of Rulemaking Regarding the 2019 Senate Bill 98 Renewable Natural Gas Programs*, Docket AR 632, Order No. 20-227 at 5 (July 16, 2020).

[23] NW Natural/2103, Chittum (citing the Oregon Clean Fuels Program, Senate Bill 98, California Low Carbon Fuel Standard and the federal Renewable Fuel Standard).

on behalf of Oregon customers, regardless of delivery to specific end-user," and the DEQ provided the requested clarification: "The biomethane can be sourced from projects anywhere in North America, as long as the biomethane is injected into a common carrier pipeline network. The natural gas utility can claim the same volume of biomethane via displacement, also known as book and claim, *without tracking the gas to a specific end-user*" (emphasis added).[24] Contrary to the Coalition's assertions, NW Natural is injecting the RNG into a common carrier pipeline network in Nebraska and, per the clarification above, does not have to track the gas to a specific end-user.

Moreover, DEQ has clarified what it means by "displacement" (or "book-and-claim") in the training materials presented to GHG reporting third-party verifiers. In a training video, DEQ states: "We do not require direct delivery of the biomethane to the supplier, and an equivalent volume of natural gas can be assumed to have been displaced as long as the purchased biomethane was nominated to a natural gas pipeline."[25] With the Lexington RNG project, NW Natural meets these requirements. NW Natural takes delivery of the energy content of the gas, as well as the environmental attributes, at the point that the project connects with the Black Hills system and injects that gas into a common

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[24] Rulemaking, Action Item A, Greenhouse Gas Emissions Program 2021 Rulemaking Climate Protection Program, at 313-14 (Dec. 16, 2021) available at: https://www.oregon.gov/deq/EQCdocs/121621_ItemA.pdf

[25] Oregon Greenhouse Gas Report Program Verifier Training – Course 5: Natural Gas Suppliers, approximately 11:45 available at: https://www.youtube.com/watch?v=FlzNhG-v16I. The Company notes that this statement was made prior to the adoption of the final CPP rules, however the CPP did not change how the Company reports GHG emissions, rather it relies on an existing process.

carrier pipeline. As shown in training materials from that same session: "Book and claim accounting can be used to show chain of custody of the environmental attributes of biomethane, rather than the physical gas itself," and "Under this system, an entity that claims biomethane in their greenhouse gas report must show that they have sole ownership of the environmental attributes of the RNG."[26] NW Natural is demonstrating that it has "sole ownership of the environmental attributes" by retaining the RTCs associated with both the Lexington RNG project and its purchases of RNG from third parties.

Finally, as explained above, the CPP framework is consistent with similar programs, including one administered by the DEQ (Oregon Clean Fuels Program), and DEQ's past statements in the Senate Bill 98 rulemaking, stating that "the flexibility of the approach helps the development of projects that would otherwise be uneconomic if physical delivery was required."[27]

III. LEXINGTON RNG PROJECT

Q. Was the Lexington RNG project producing RNG as of the date of your Direct Testimony—December 17, 2021?

A. No. In my Direct Testimony, I stated that the Lexington RNG project is scheduled to begin start-up operations in January 2022 and fully commence service the following month.[28]

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[26] NW Natural/2102, Chittum.

[27] *In the Matter of Rulemaking Regarding the 2019 Senate Bill 98 Renewable Natural Gas Programs*, Docket AR 632, Order No. 20-227 at 5 (July 16, 2020).

[28] NW Natural/1100, Chittum/6-7.

Q. Did the Lexington RNG project begin start-up operations in January 2022 and is it currently in commercial operation?

A. Yes. The Lexington RNG project began start-up operations on January 13, 2022, when it first began injecting RNG into Black Hills' pipeline system. The project began commercial operations on January 24, 2022, and is currently producing RNG.

Q. Please describe the commercial operations of the Lexington RNG project.

A. The Lexington RNG project has been producing RNG since January 2022 and the Company expects daily production to continue to increase slowly as the lingering effects of COVID-19 on Tyson operations recede and operational issues associated with a new project are resolved. Given these issues, however, the Company estimates that RNG production will be approximately **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** of its initial estimates during the first 12-24 months of operation.

Q. Please describe the effects of COVID-19 and other start-up operational issues and how they will be resolved.

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]**.

Q. Are NW Natural, BioCross, and Tyson all working together to resolve these initial operating issues?

A. Yes. The Company is committed to resolving these issues and increasing production at the Lexington RNG project. BioCross, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY**

CONFIDENTIAL] is also highly motived to resolve these issues. Finally, Tyson's royalty that it receives is directly related to **[START HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL],** and so it is also incented to work to resolve these issues.

Q. Has NW Natural updated the cost-of-service analysis of the Lexington RNG project?

A. Yes. The Reply Testimony of Kyle Walker and Robert Wyman has an updated cost-of-service analysis (NW Natural/2300, Walker-Wyman). The cost-of-service analysis also updates the operating costs and revenues of the project, including increasing the revenue that NW Natural receives from selling the energy content of the gas. This increased revenue is based on the forward cost curve for the Test Year at the relevant point where the physical gas is sold (NGPL-Midcont Pool) minus **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL**] per dekatherm. The reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per dekatherm reflects the price that NW Natural pays a natural gas marketer to sell the physical gas the project produces. The revenue from these sales is netted into the cost that customers will pay for the Lexington RNG project. As a result of these changes the total cost of service for the Lexington RNG project in the Test Year has decreased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. AWEC argues that the amount that NW Natural pays BioCross should be limited. What is your response?

A. The premise of AWEC's argument that the utility could have owned 100 percent of the Lexington RNG project is incorrect. NW Natural needed BioCross to develop the Lexington RNG project, as BioCross put the initial project concept together, secured the initial relationship and interest with Tyson, and conducted the initial evaluation of the gas potential and equipment costs, well before NW Natural was ever aware of the Lexington facility. In short, NW Natural could not have developed the project without BioCross. As such, BioCross shares in the benefits if the Lexington RNG project is successful, as well as sharing in risk. This is a very typical developer relationship in RNG project development.

Q. AWEC suggests that ratepayers would be better off if NW Natural bought out BioCross' interest prior to the Lexington RNG project commencing commercial operation. Do you agree?

A. No. If NW Natural pursued that strategy, it would have shifted all the project's risk to NW Natural. In other words, BioCross would have profited from the project up front, whether it were successful or not in the long run, and would have borne none of the risk. Instead of pursuing that approach, NW Natural believed it was better to have BioCross profit only to the extent that the project was successful and shoulder some of the risks of the project. NW Natural continues to believe that its approach is superior to AWEC's suggestion of giving BioCross an upfront buyout whether the project were successful or not. As I stated above, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]**.

IV. RESPONDING TO STAFF'S CONCERNS REGARDING FUTURE RNG PROCUREMENT

Q. In its Direct Testimony, what is Staff's conclusion regarding the Lexington RNG project?

A. Staff states that **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** to date of the Lexington RNG project appear to be prudent."[29]

Q. Staff states that NW Natural has not demonstrated that RNG project development and operation is a "core competency" of its regulated operations.[30] What is your response?

A. The Company has devoted significant resources in developing its RNG expertise. In addition to myself, the Company has hired a renewables team with significant expertise in RNG development. We have hired individuals with direct experience in biogas project development, renewable gas development, renewable energy project management, and renewable energy asset management.

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[29] Staff/1700, Muldoon/22.

[30] *Id.* at 20.

Q. Staff states that it is not "essential" for RNG development to take place within the regulated utility. Why do you believe that development within the regulated utility makes sense for NW Natural's customers?

A. As I stated in my Direct Testimony, NW Natural intends to build a diversified portfolio of resources that includes both purchases and investments. This strategy will ensure that the Company is not overly dependent on one market, project or counterparty. Staff states that the Company could pursue RNG project development outside of the utility and purchase the RNG from a non-regulated affiliate. While the Company does not foreclose this possibility, it comes with its own challenges. NW Natural does not control or operate its non-regulated affiliates under NW Natural Holding Company. A non-regulated affiliate will seek to maximize the revenue it seeks for its RNG and, in keeping with its fiduciary responsibility to its shareholders, would not offer RNG to the utility at a price below what it could seek in other markets and from other purchasers. Therefore, there is no assurance that a non-regulated affiliate will transact with NW Natural to meet its Senate Bill 98 targets or compliance with the CPP. In addition, transactions between affiliates are subject to the "lower of cost or market" standard in OAR 860-027-0048(4)(e). If this standard is interpreted to mean that the non-regulated affiliate must sell RNG to the regulated utility at less than a market price, then it would prevent RNG sales to the utility. Instead, the non-regulated affiliate would sell the RNG to an entity that would pay the market price.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibits of Anna K. Chittum

LEXINGTON RNG PROJECT
EXHIBITS 2101-2103

June 6, 2022

EXHIBITS 2101-2103 – LEXINGTON RNG PROJECT

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Exhibit of Anna K. Chittum

LEXINGTON RNG PROJECT
EXHIBIT 2101

June 6, 2022

AGA Net Zero Emissions Opportunities for Gas Utilities

Overview of RNG & Hydrogen Components

03/28/2022

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Disclaimer

- Overview of study's use of RNG & Hydrogen
- RNG supply details
- Hydrogen use cases

Agenda

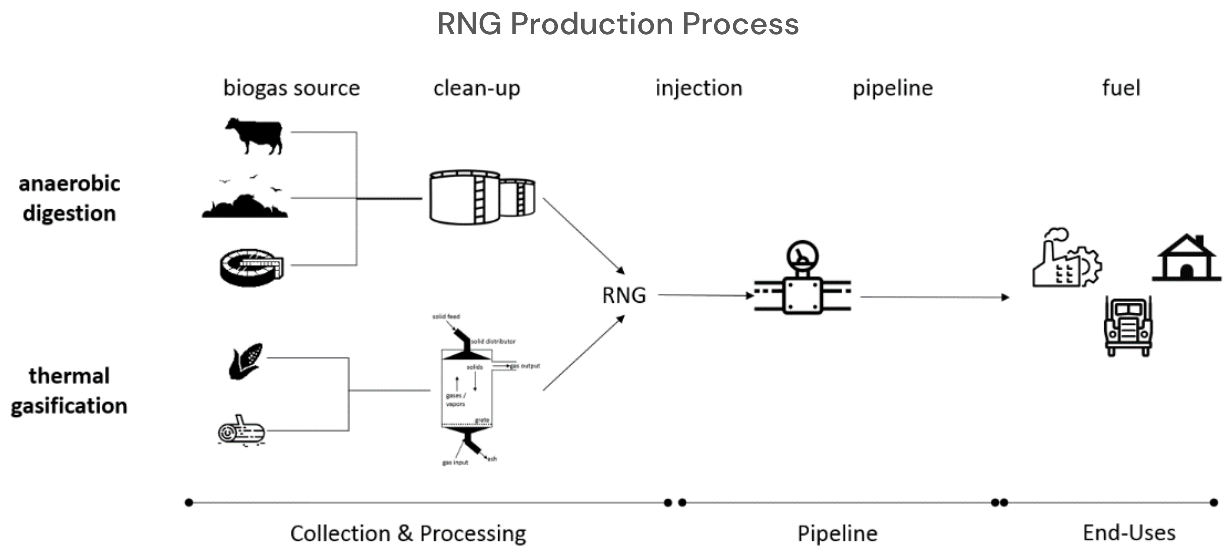
Brief study RNG / H2 overview

Categories of Supply-Side Resources in the Study

- Geological natural gas:
  - This portion of remaining gas demand which continues to be met by shale / conventional natural gas production
- Renewable natural gas (RNG)
  - This includes RNG produced by Anaerobic Digestion and Thermal Gasification from a variety of feedstocks
- Hydrogen blending into gas supply:
  - Hydrogen that is assumed to be mixed into existing gas infrastructure without requiring significant infrastructure upgrades
- Methanated hydrogen (RNG)
  - This supply represents RNG (or low carbon gas that can be blended without limit in existing gas infrastructure) that was produced from a clean hydrogen feedstock, through the addition of biogenic CO2 in a methanation process.
- Dedicated hydrogen infrastructure:
  - This represents the build out of new infrastructure to enable targeted customers/clusters to convert to higher levels of hydrogen use. These volumes include hydrogen used for industry (all scenarios) and hydrogen used in residential/commercial buildings (one scenario only), but do not include hydrogen used in the transportation sector for fuel cell vehicles.

RNG supply details

- Renewable natural gas (RNG) is a pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent emissions than geological (conventional) natural gas.
- RNG is generally produced from waste-based feedstocks:
  - Includes landfill gas, wastewater, food waste, animal manure, agricultural and forestry residues, and energy crops.
  - Waste-to-energy pathways such as RNG displace fossil fuel consumption and avoid conventional waste management emissions.



Renewable Natural Gas

RNG Supply – AGF 2019 Report

- In 2019 ICF completed a study of RNG supply potential for the AGF, looking out to 2040.
  - The AGF study looked at data on the resource availability for different RNG feedstock options and calculated a 'Technical Potential'.
  - The AGF study included 'High' and 'Low' cases where different percentages of the technical potential would be realized.
  - The 'High Case' in the 2019 AGF study included 3,800 tBtu of RNG supply, about 27% of the ~14,000 tBtu technical potential.
- These supply cases were not developed or framed around specific policy objectives or GHG targets.
- Instead, purpose was to illustrate the diversity and volume of RNG potential with different, relatively conservative, constraints for each feedstock.

Figure 1. Estimated Annual RNG Production, Low Resource Potential Scenario, tBtu/y

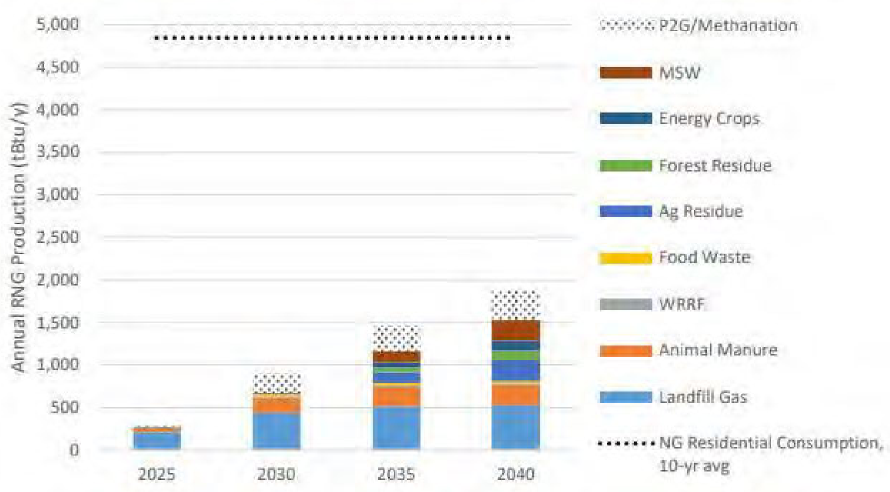
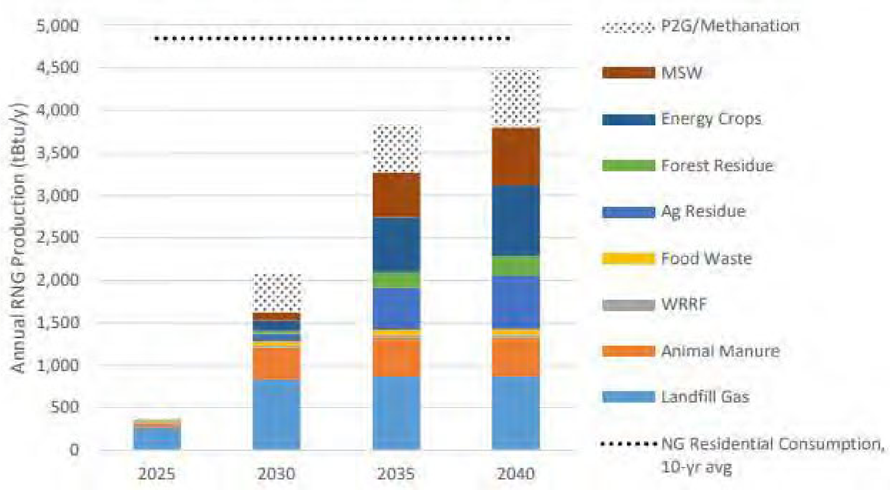


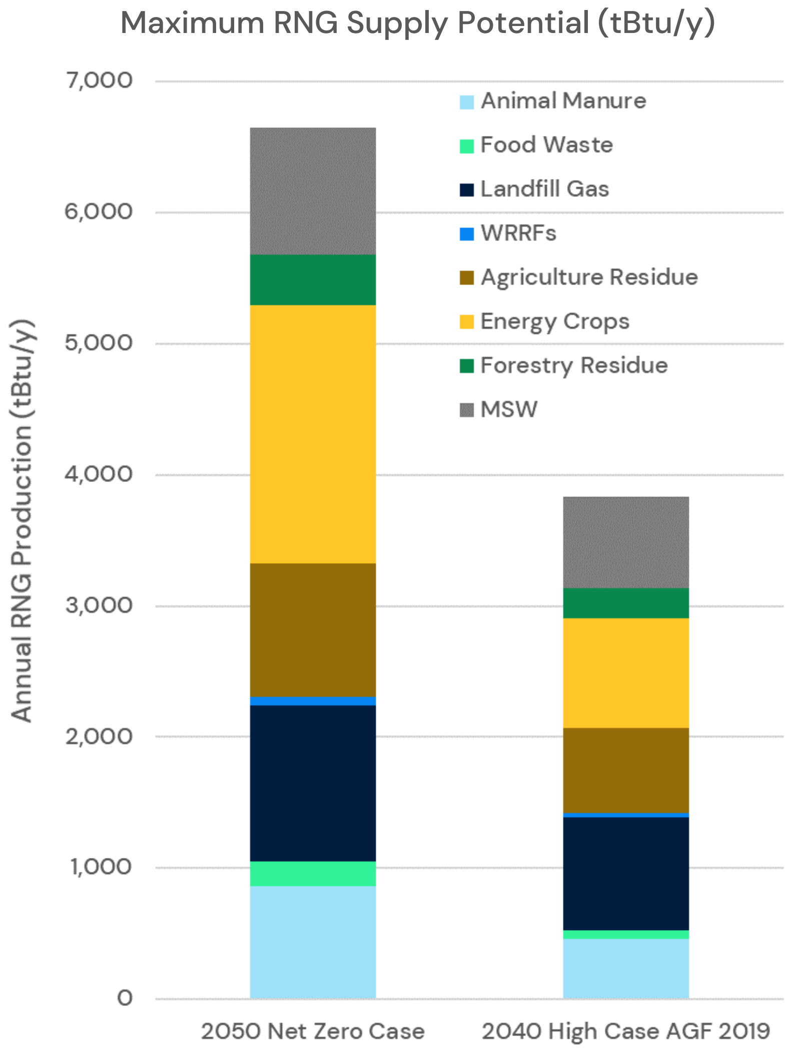
Figure 2. Estimated Annual RNG Production, High Resource Potential Scenario, tBtu/y



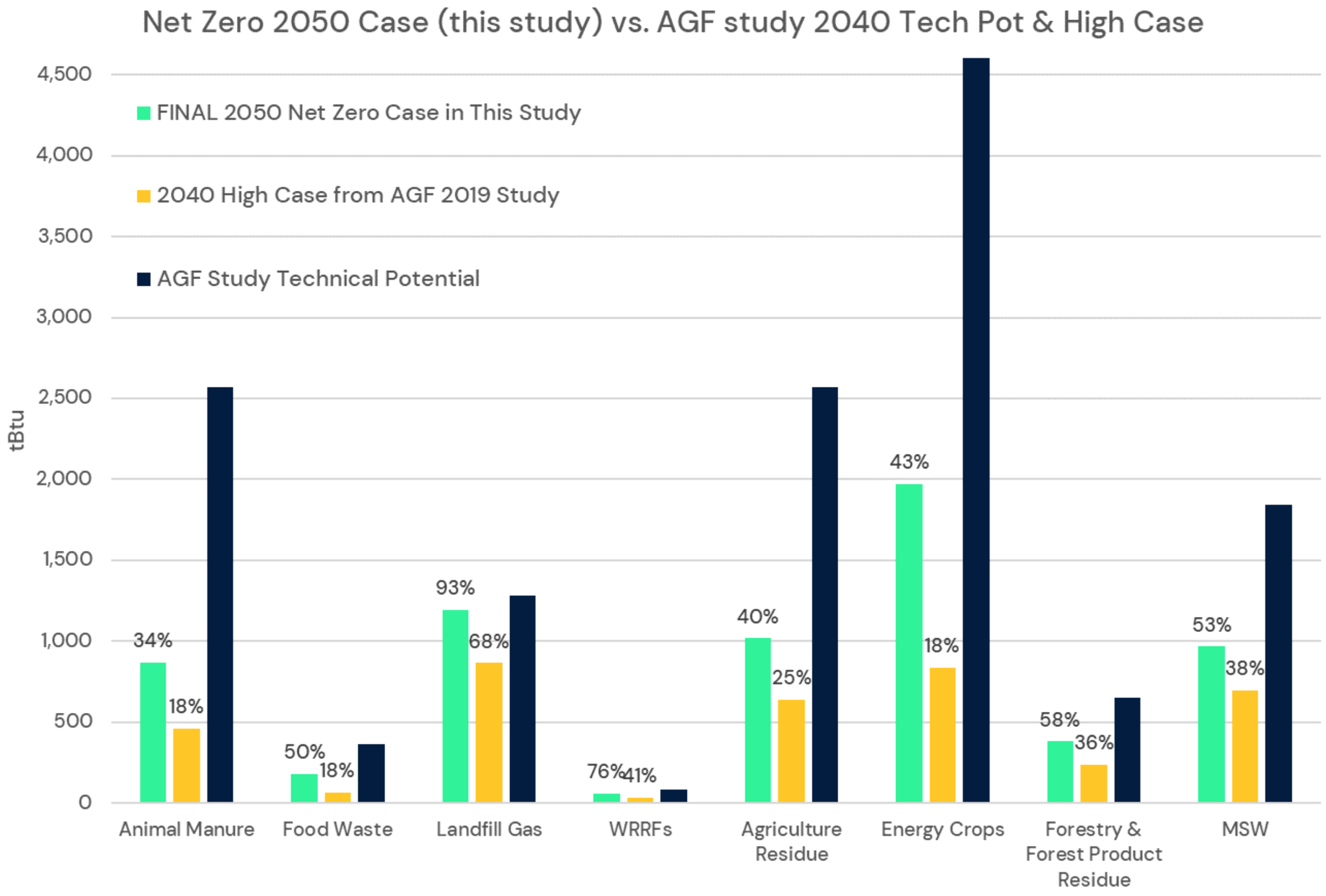
https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

- Since the 2019 report, heightened focus on aggressive long-term GHG emission reductions, referred to as 'deep decarbonization'.
  - Deep decarbonization typically reflects emission reduction targets of between 80–100% by 2050 (e.g. Net-Zero).
- Deep decarbonization requires aggressive deployment of emission reduction measures across the economy:
  - GHG-free electricity grids, comprehensive transportation electrification, and deployment of low or zero carbon fuels.
  - Renewed focus on the role that bioenergy can play to reach these aggressive GHG emission reduction targets.
- RNG supply potential was re-evaluated for AGA's 2021 Net-Zero report in this context:
  - Focused on 2050 timeframe, consistent with aggressive GHG targets.
  - 2050 Net-Zero RNG supply case uses same feedstock data from 2019 report, but captures closer to 50% of technical potential in 2050.
  - Supply increased to reflect 'all hands on deck' approach to economy-wide deep decarbonization, while maintaining a conservative approach to feedstock constraints and limitations.

RNG Supply – 2021 Net-Zero Case



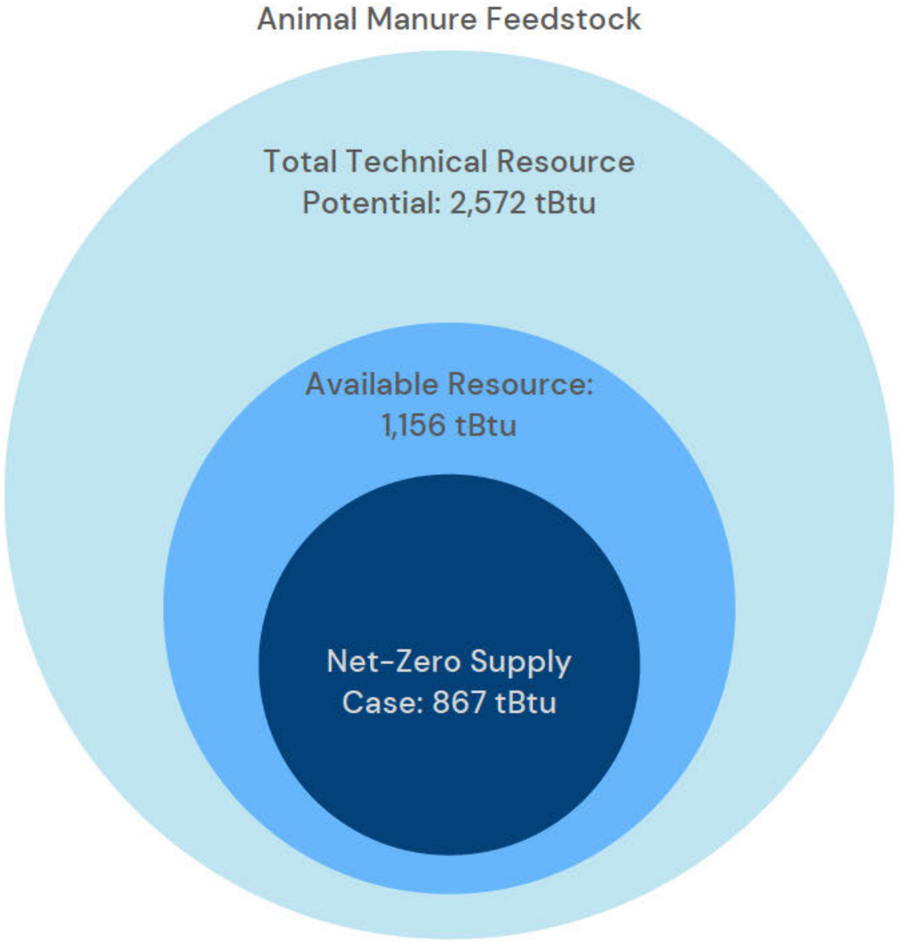
- AGF 2019 High Case captured 27% of all available feedstocks:
  - Ranging from 68% for landfill gas, to 18% for animal manure and energy crops.
- AGA 2021 Net-Zero case increased utilization, captured 48% of all available feedstocks:
  - Landfill gas is highly utilized.
  - Conservative constraints continue to limit supply of animal manure, agricultural residue and energy crops (34-43%).



RNG Supply – Utilization Comparison

RNG Supply – Feedstock Utilization Example

- *Total Technical Resource Potential* reflects all animal manure produced from all animal populations:
  - Biomass estimate derived from daily manure production rates for beef cows, dairy cows, broiler chickens, layer chickens, turkeys and swine.
  - Total reflects collection of all manure.
- Technical Availability Factors (TAF) are then applied to estimate *Available Resource*:
  - From a practical perspective, not all manure can be collected and utilized for RNG production, e.g. dispersed in fields.
  - TAF varies by animal type, e.g. dairy and chickens have TAF of 50%; beef and swine 20%.
- Resource scenarios, such as the *Net-Zero Supply Case*, applies additional constraint on utilization of *Available Resource*, e.g.:
  - *Net-Zero Supply* case captures 75% of *Available Resource*.
  - AGA 2019 High Scenario captured 60% of *Available Resource*.



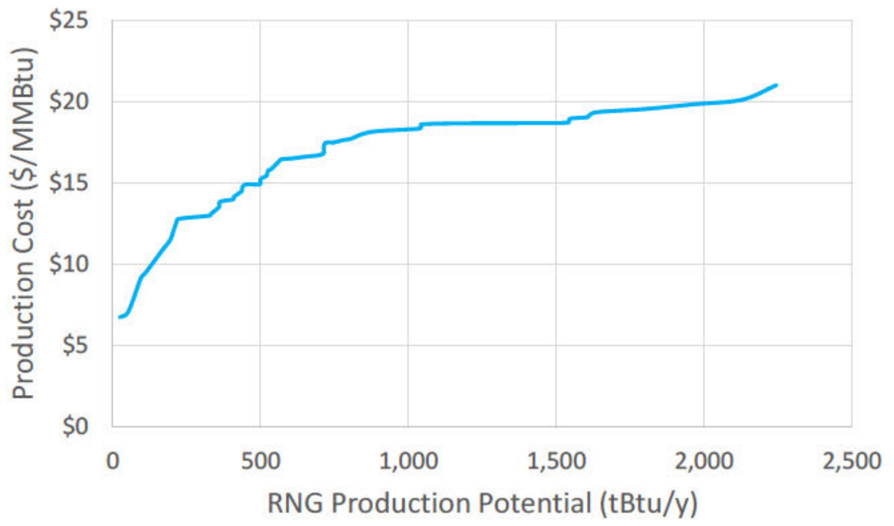
- AGA Net-Zero 2050 case framed around long-term and economy-wide deep decarbonization.
  - i.e. pushing hard on all emission reduction options across the economy, not just RNG.
- More optimistic assumptions on feedstock utilization.
- Case captures less than half of all available feedstocks.
  - 54% of anaerobic digestion feedstocks.
  - 45% of thermal gasification feedstocks.
- Over half of available biomass that could be used to produce RNG is not directed towards RNG production.
  - Allows for other sectors of the economy to capture and utilize the biomass, as needed (e.g. liquid biofuels).

Feedstock for RNG		Volume (tBtu)	Key Parameter
Anaerobic Digestion	Animal manure	867	75% of technically available
	Food waste	182	95% @ $100/ton
	LFG	1,195	95% eligible landfills
	WRRF	62	95% of facilities w/ >3.5MGD
	Subtotal & Utilization Percentage	**2,306**	**54%**
Thermal Gasification	Agricultural residue	1,019	80% @ $50/ton
	Energy crops	1,972	60% @ $50/ton
	Forestry & forest product residue	381	80% @ $50/ton
	MSW	968	80% @ $50/ton
	Subtotal & Utilization Percentage	**4,339**	**45%**
Total & Utilization Percentage		**6,645**	**48%**

RNG Supply – AGA Net-Zero 2050

- RNG production cost estimates reflect the all-in cost to collect, clean and deliver the RNG up to the point of injection into a common-carrier pipeline.
- Cost estimate do not reflect potential value of environmental attributes associated with RNG, such as when used in the transportation sector (Federal Renewable Fuel Standard).
- In the 2019 AGF Report, ICF estimated that the majority of the RNG produced in the High Resource Potential scenario would be available in the range of $7-$20/MMBtu.
- ICF also found that there was potential for cost reductions as the RNG for pipeline injection market matured, production volumes increased, and the underlying structure of the market evolved.

Combined RNG Supply-Cost Curve in 2040 (ICF AGF Report 2019)



→ RNG Cost Assessment – AGF 2019 Summary

Hydrogen discussion

- For RNG, the key limiting factors would be the total RNG feedstock potential (including competition from other sectors like Power), as well as RNG supply costs

- For Hydrogen, this study assumed the constraints are only limitations on customers' ability to acquire and use hydrogen (not H2 supply)
  - If hydrogen production is limited only by renewable and/or nuclear generation expansion, as well as SMR with CCS, the study working group was comfortable assuming that 'as much hydrogen as needed' can be made seems in line with the types of actions needed to hit net zero (for any pathway)
  - Methanated hydrogen was an exception to that – as it could be limited by the availability of CO2 for methanation of H2
  - Blending limits in gas distribution systems, limits from existing customer equipment, and safety considerations will all be key factors that could prevent customer adoption
  - Costs to convert to new hydrogen infrastructure and equipment, as well as H2 supply, also relevant

Limiting Factors for Hydrogen Use

Study included hydrogen use through the following five approaches

1 H2 Blended into NG Supply

2 H2 Methanated into Synthetic NG & Blended into NG Supply

3 H2 Clusters for Industry & Power Generation

4 New Customers in Targeted Regions Built for 100% H2

5 Targeted Conversion of Existing Customers to 100% H2

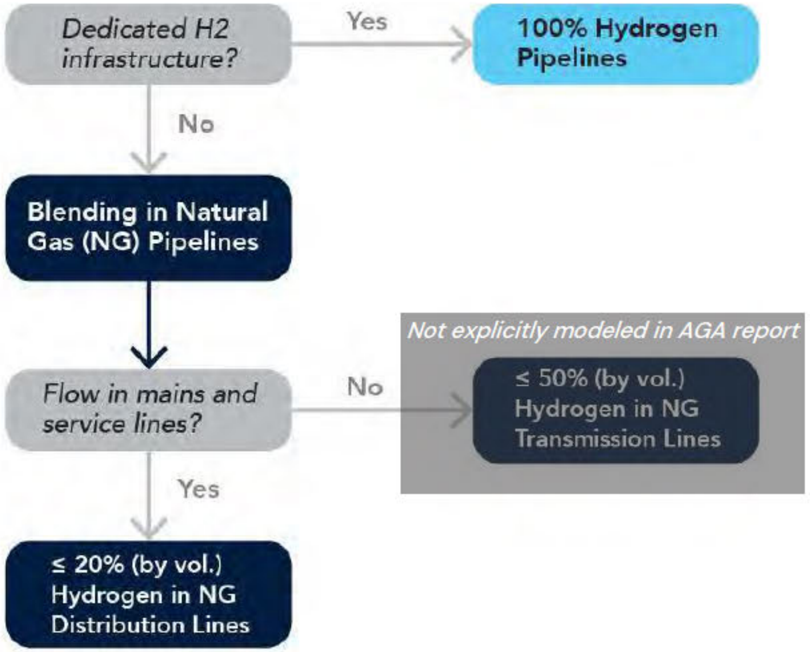
6 Other Approaches

E.g., H2 powering distributed fuel cells

Hydrogen Generation, Storage, Transportation

Hydrogen Blending into Natural Gas Supply

- Up to 7% on energy basis (20% by volume) by 2035
  - Hydrogen can blend in limited amounts into natural gas pipelines
  - Existing research suggests that blends up to 20% H2 by volume may be feasible in existing pipes, depending on pipeline material, without major infrastructure upgrades
  - Not all study scenarios went up to the 20% blend – as focus was demonstrating diversity of approaches



Methanated Hydrogen

- Carbon-neutral methane that can be blended without limit in existing infrastructure
- Produced by methanating clean hydrogen with biogenic CO2
- Functionally equivalent to renewable natural gas
  - Essentially adds to the aforementioned RNG supply from conventional anaerobic digestion and thermal gasification RNG processes (*but methanated hydrogen volumes are counted separately from the RNG supply / not included in the RNG section totals*)
- Limitation is the availability of 'carbon neutral CO2' for this process, to ensure the methanated hydrogen can be considered a renewable / low carbon fuel
  - This study indicates that a variety of biogenic CO2 options could be available – but for the potential here we quantified the Methanated Hydrogen potential based on an assumption that the RNG thermal gasification processes are paired with clean hydrogen, taking advantage of the biogenic CO2 emissions they produce and in effect doubling the RNG produced by thermal gasification
  - Thermal gasification RNG production creates enough biogenic CO2 to theoretically triple to quadruple RNG output through hydrogen addition – but it will also get harder / more expensive to utilize all available CO2
  - Some other studies includes CO2 from DAC – to increase available CO2 options beyond biogenic CO2

Two key methanation reactions:

$CO_2 + 4H_2 \rightarrow CH_4 + 2\ H_2O$

$CO + 3H_2 \leftrightarrow CH_4 + H_2O$ *(this is the Steam Methane Reforming reaction run backwards)*

Dedicated Hydrogen Infrastructure

- Customer's hydrogen needs could be met through newly built hydrogen pipelines, conversion of existing natural gas pipelines, or on-site hydrogen production

- All scenarios include a portion of industrial customers using 100% H2 (~10%), with higher levels in Scenario 4 (~17%)

- One scenario also includes some residential and commercial new construction customers using 100% H2 starting in 2040 and some existing residential and commercial gas buildings converted to use 100% H2 starting in 2045

Example commercially-available hydrogen combined heat and power (CHP) system

Hydrogen Production

- Focus in the report is on using 'clean hydrogen' with less emphasis on green vs. blue, but for the upstream emissions analysis assumptions on the supply mix were required
- Hydrogen supplies of interest to LDCs for net-zero targets were simplified to blue, green, and pink hydrogen
- Study assumed the initial adoption of hydrogen produced from conventional means (namely, steam methane reforming of natural gas) and from anticipated growing clean hydrogen supplies

	Gray Hydrogen	Blue Hydrogen	Green Hydrogen	Pink Hydrogen
Process	Steam methane reforming	Steam methane reforming with carbon capture and sequestration	Electrolysis	Electrolysis
Source	Methane	Methane	Renewably-generated electricity	Nuclear electricity generation

Assumed Supply Mix	2020	2025	2030	2040	2050
Green H2 (Renewable Electrolysis)	1%	20%	30%	52%	75%
Blue H2 (SMR with CC)	0%	5%	50%	48%	25%
Grey H2 (SMR)	99%	75%	20%	0%	0%

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About ICF

ICF (NASDAQ:ICFI) is a global consulting and digital services company with over 7,000 full- and part-time employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future.

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UG 435 / UG 411

NW Natural

Exhibit of Anna K. Chittum

LEXINGTON RNG PROJECT
EXHIBIT 2102

June 6, 2022

Oregon Greenhouse Gas Reporting Program
Verifier Training

Course 5: Natural Gas Suppliers

Matt Steele
Greenhouse Gas Reporting Specialist
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Agenda

1. Sector overview
2. Natural gas supplier reporting requirements
3. Verification process
4. Reporting examples

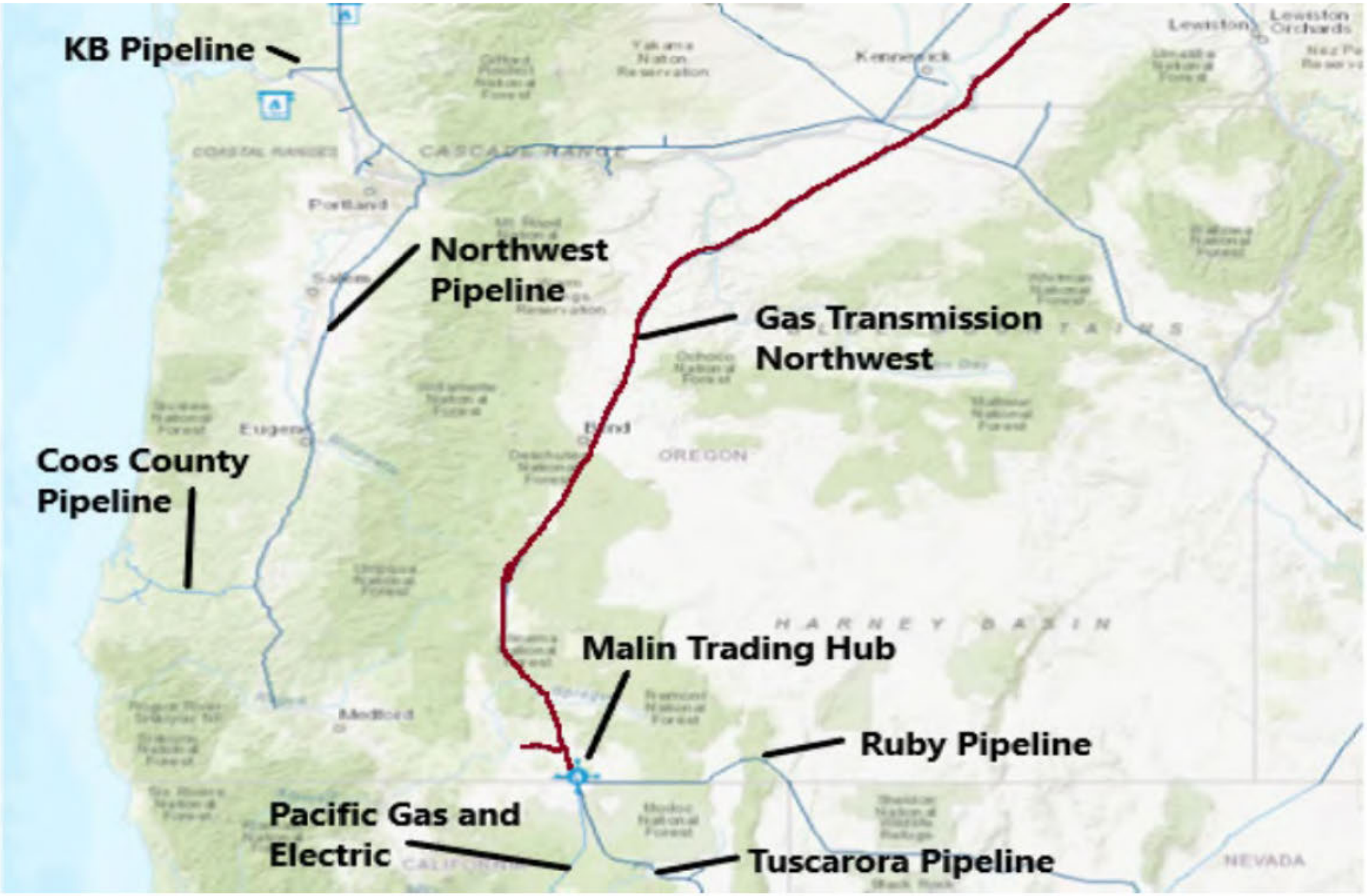
Supplemental materials

I. Acronyms and definitions

Agenda

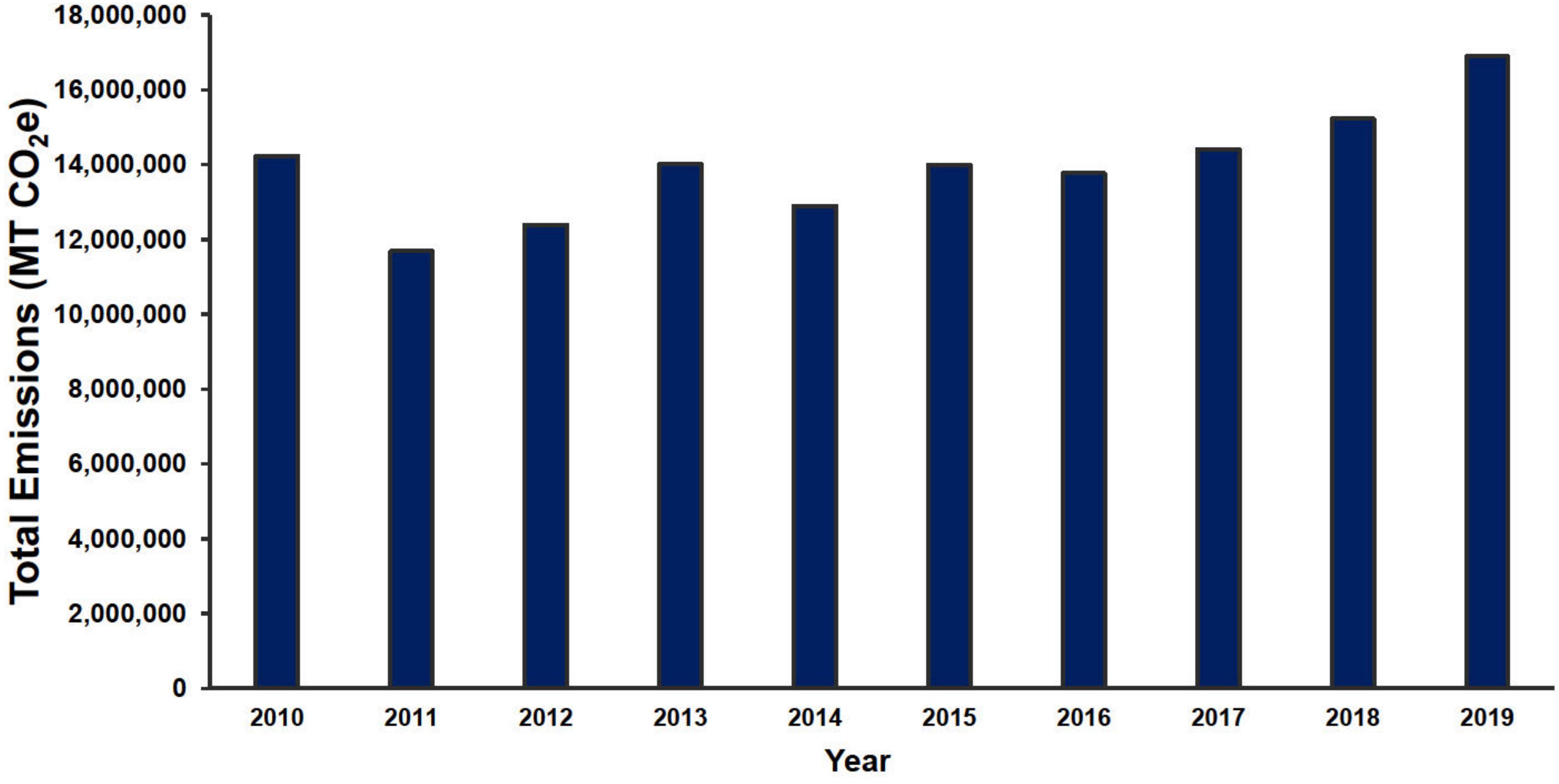
1. **Sector overview**
2. Natural gas supplier reporting requirements
3. Verification process
4. Reporting examples

Natural gas transmission pipelines



EIA Energy Mapping System: https://www.eia.gov/state/maps.php

Natural gas emissions



https://www.oregon.gov/deq/FilterDocs/GHGNatGasSuppliers.xlsx

Agenda

1. Sector overview

2. Natural gas supplier reporting requirements

3. Verification process

4. Reporting examples

Regulations

[Greenhouse Gas Reporting Program]

[Third Party Verification]

Reporting deadline

- Deadline for GHG reporting to DEQ is **March 31.**
- Verification statements must be submitted to DEQ by **August 31**.

DEQ

Reporting requirements

Natural gas supplier regulation

- Applies to any entity that produces, imports, sells, or distributes natural gas in Oregon
- Must report the total volume (Mscf) and energy (MMBtu) of natural gas delivered and emissions from complete combustion of this gas
- Emissions quantified using methodology in 40 C.F.R. part 98, subpart NN for CO_2 emissions and subpart C for CH_4 and N_2O emissions

Natural gas supplier regulation: OAR 340-215-0115

3PV applicability

- 3PV required for all natural gas suppliers who report emissions of at least 25,000 MT CO_2e
- **Exception**: Does not apply to interstate pipelines
- **Result** → Only the 3 local distribution companies will require verification

1. *Northwest Natural*
2. *Avista Utilities*
3. *Cascade Natural Gas Corporation*

Third party verification regulation: OAR 340-272-0120

Fuels to report

1. Natural gas
2. Compressed natural gas (CNG)
3. Liquefied natural gas (LNG)
4. Biomethane

Natural gas supplier regulation: OAR 340-215-0115

Types of natural gas suppliers

1. In-state producers
2. Local distribution companies (LDCs)
3. Interstate pipelines
4. Importers

Natural gas supplier regulation: OAR 340-215-0115

Types of natural gas suppliers

1. In-state producers

Any person who produces natural gas or who refines, treats or otherwise processes biogas into biomethane in Oregon.

Natural gas supplier regulation: OAR 340-215-0115

Types of natural gas suppliers

2. Local distribution companies (LDCs)

A legal entity that owns or operates distribution pipelines and that physically delivers natural gas to end users in the state. This includes public utility gas corporations and intrastate pipelines engaged in the retail sale, delivery, or both, of natural gas. This excludes interstate pipelines.

- Northwest Natural
- Avista Utilities
- Cascade Natural Gas Corporation

Natural gas supplier regulation: OAR 340-215-0115

Types of natural gas suppliers

3. Interstate pipelines

A natural gas pipeline delivering natural gas across state boundaries for use in Oregon and that is subject to rate regulation by the Federal Energy Regulatory Commission (FERC).

Natural gas supplier regulation: OAR 340-215-0115

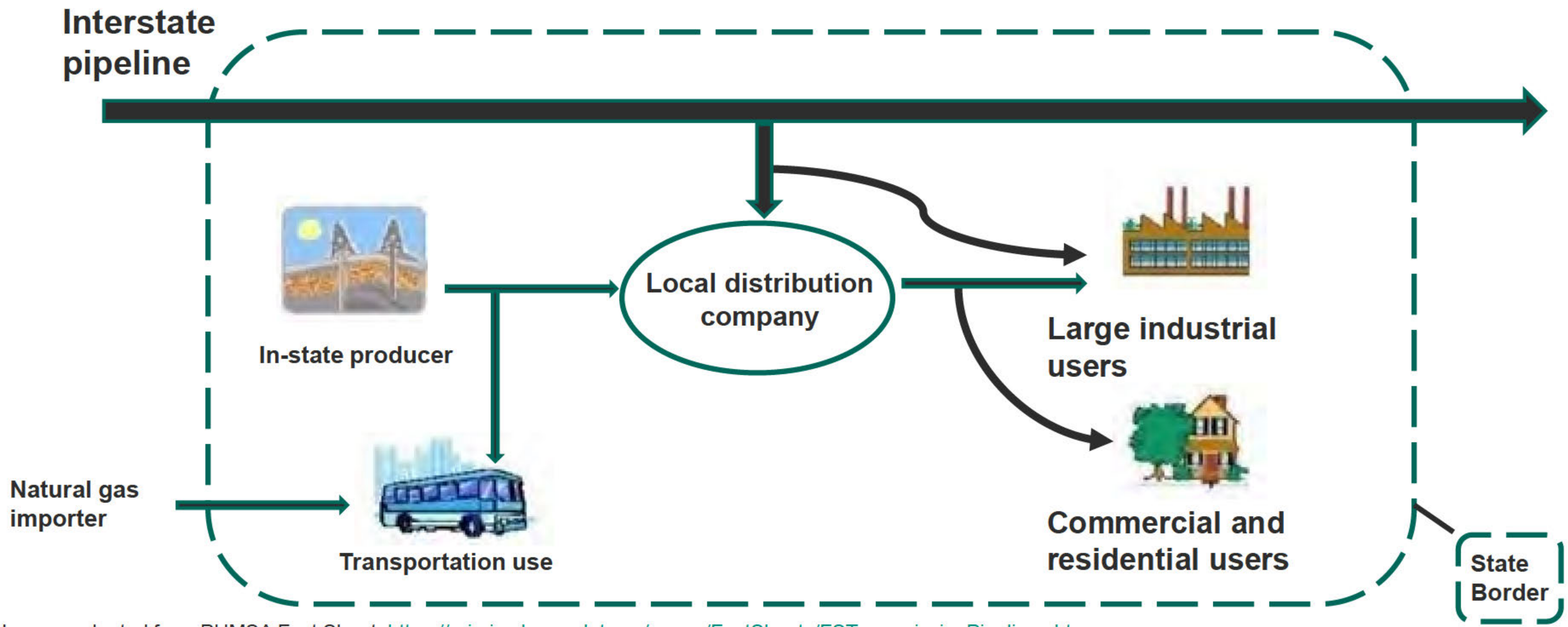
Types of natural gas suppliers

4. Importers

Any person who brings natural gas into Oregon by means other than a pipeline distribution system or interstate pipeline, such as by rail or truck.

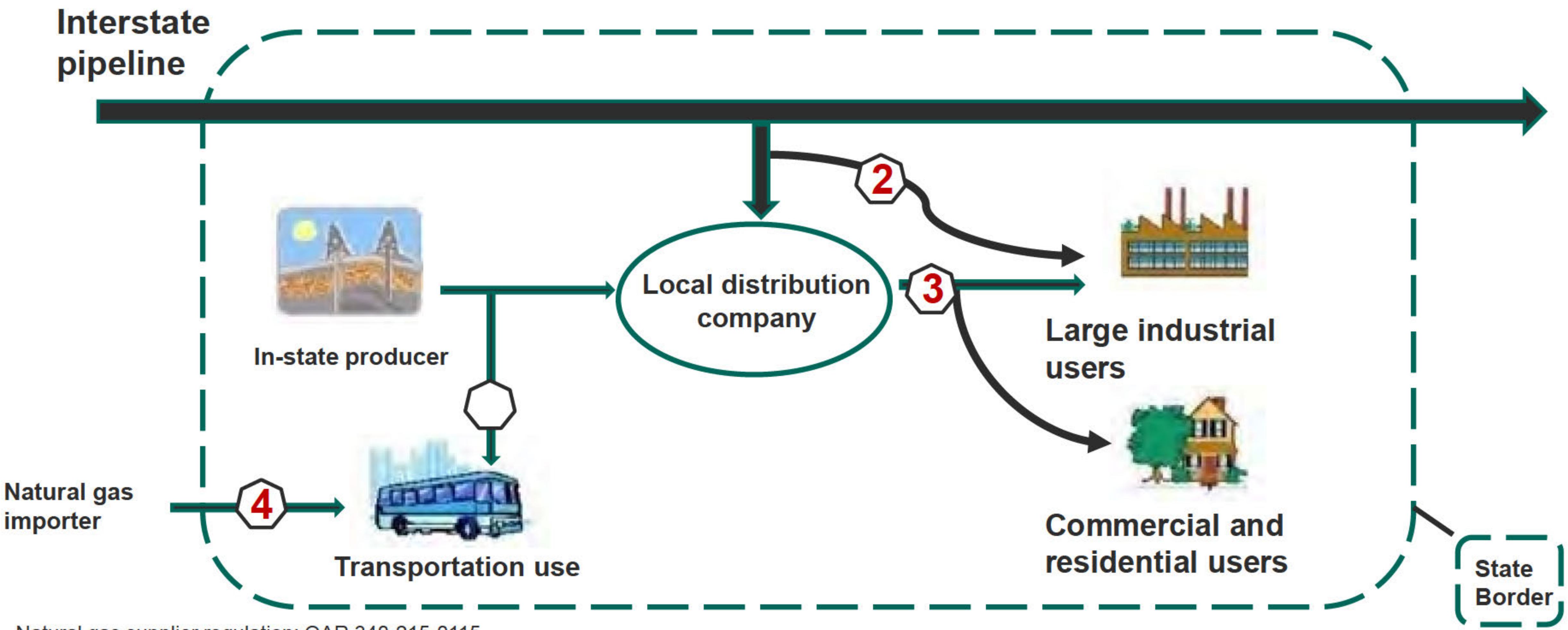
Natural gas supplier regulation: OAR 340-215-0115

Natural gas supplier reporting



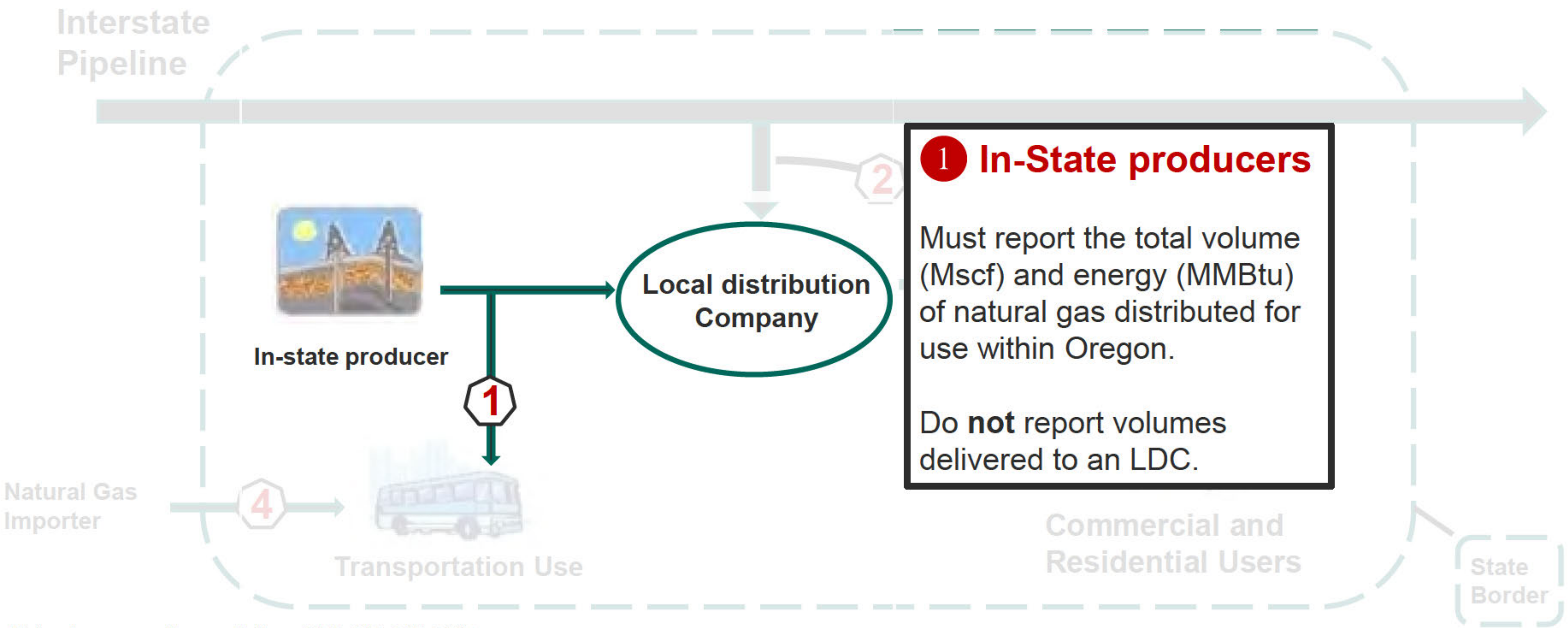
Images adapted from PHMSA Fact Sheet: https://primis.phmsa.dot.gov/comm/FactSheets/FSTransmissionPipelines.htm

Natural gas supplier points of regulation



Natural gas supplier regulation: OAR 340-215-0115

Natural gas supplier points of regulation



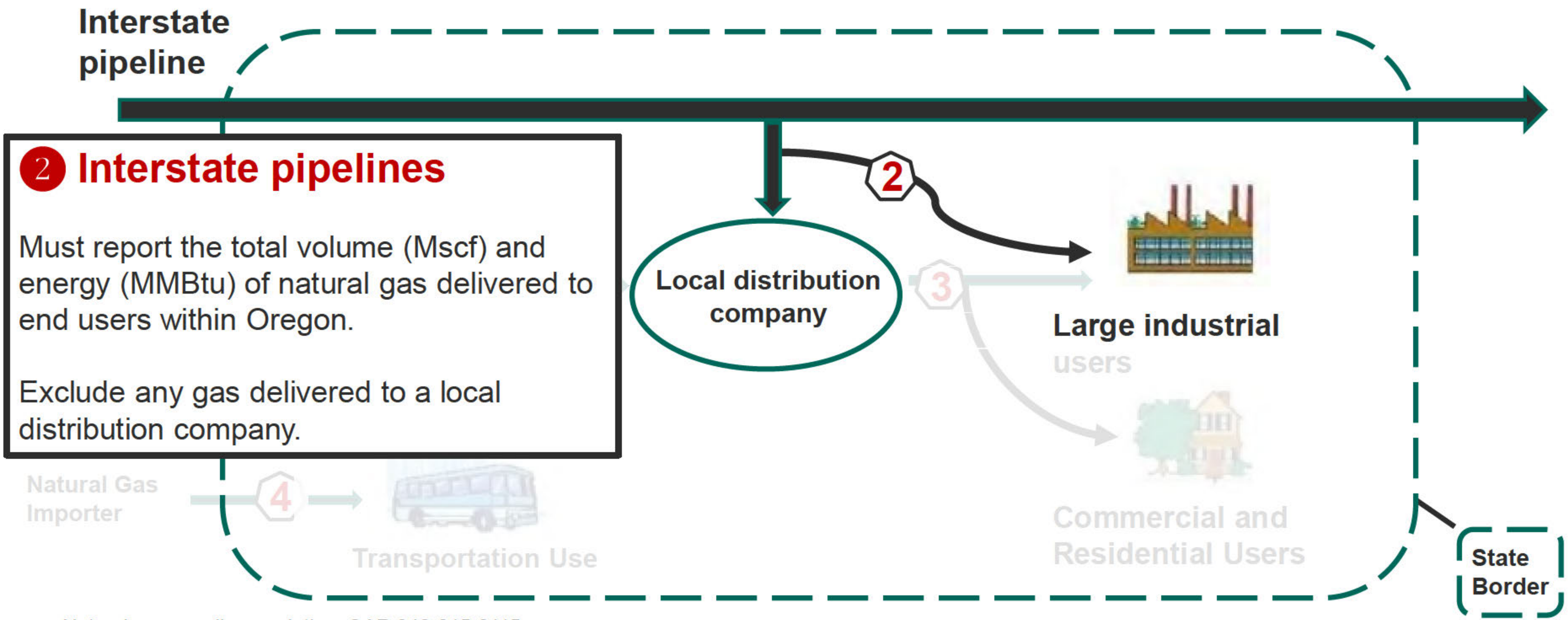
1 In-State producers

Must report the total volume (Mscf) and energy (MMBtu) of natural gas distributed for use within Oregon.

Do **not** report volumes delivered to an LDC.

Natural gas supplier regulation: OAR 340-215-0115

Natural gas supplier points of regulation



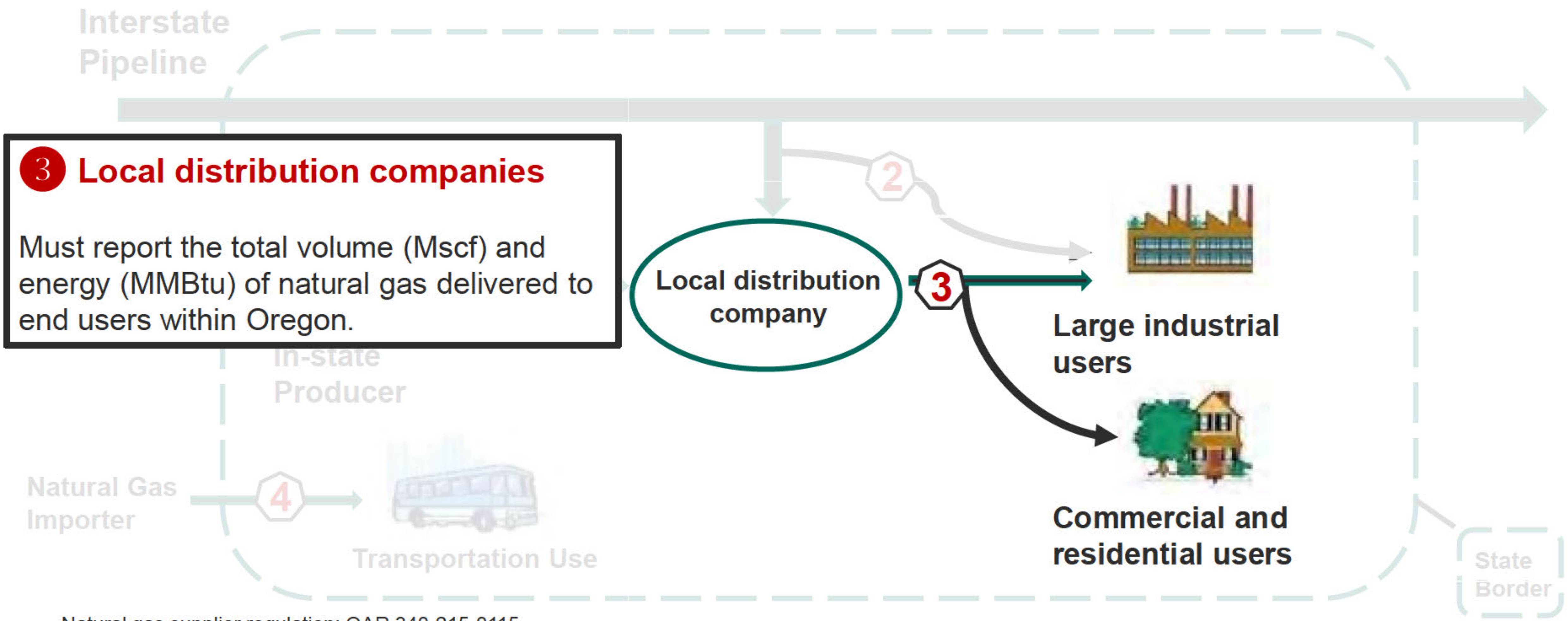
2 Interstate pipelines

Must report the total volume (Mscf) and energy (MMBtu) of natural gas delivered to end users within Oregon.

Exclude any gas delivered to a local distribution company.

Natural gas supplier regulation: OAR 340-215-0115

Natural gas supplier points of regulation

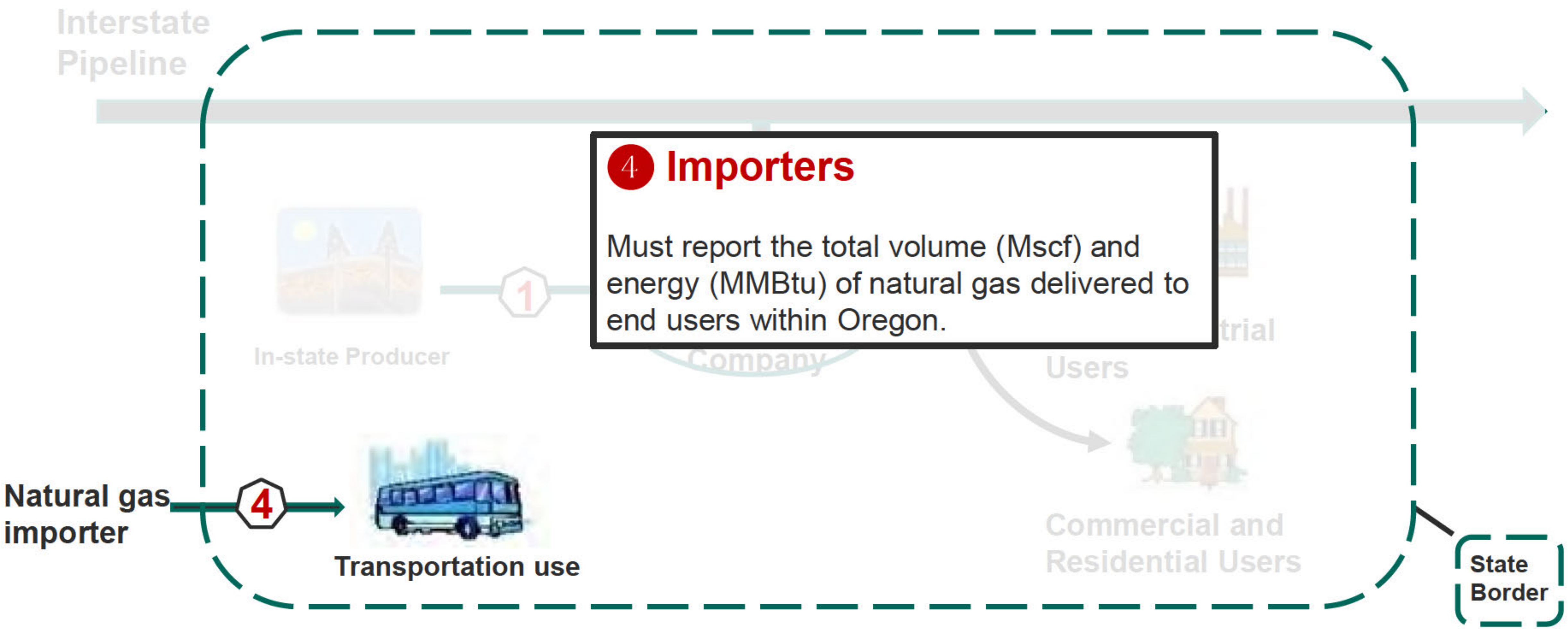


3 Local distribution companies

Must report the total volume (Mscf) and energy (MMBtu) of natural gas delivered to end users within Oregon.

Natural gas supplier regulation: OAR 340-215-0115

Natural gas supplier points of regulation



4 Importers

Must report the total volume (Mscf) and energy (MMBtu) of natural gas delivered to end users within Oregon.

Additional reporting requirements

Large end-users

- Report volumes of natural gas delivered to each end-user that receives at least 460,000 Mscf annually
- Provide contact information to identify the end-user facility
- These volumes are not removed from the reported total delivered volume

Natural gas supplier regulation: OAR 340-215-0115

Additional reporting requirements

Natural gas marketers

Each natural gas supplier must also report identifying information for natural gas marketers or transport customers who contract use of their infrastructure:

- Contact information to identify the marketer
- Volume of natural gas transported for each marketer (requested field in the reporting tool, but not required by the regulation)

Natural gas supplier regulation: OAR 340-215-0115

Additional reporting requirements

Biomethane (1/3)

Any natural gas supplier that delivers biomethane to end users must report:

- Identifying information on the biomethane producer
- Volume of biomethane purchased from each producer

Only applicable if the natural gas supplier has purchased the biomethane for delivery to an end user, or if the supplier can provide the required documentation on behalf of an end user transportation customer.

Reporting biomass-derived fuels: OAR 340-215-0044(5)

Additional reporting requirements

Biomethane (2/3)

- Book and claim accounting can be used to show chain of custody of the environmental attributes of biomethane, rather than the physical gas itself.
- Under this system, an entity that claims biomethane in their greenhouse gas report must show that they have sole ownership of the environmental attributes associated with this volume.
- The claimed volume of biomethane delivered must be linked to an equivalent MMBtu of biomethane injected into a North American common carrier pipeline

Reporting biomass-derived fuels: OAR 340-215-0044(5)

Additional reporting requirements

Biomethane (3/3)

- The claimed volume can only be linked to one volume of natural gas delivered by the natural gas supplier - No double counting
- May report the same volume of biomethane to the CFP, federal RFS, and the GHGRP, provided this is all linked to one volume and use
- The environmental attribute must be retired when reported as delivered
- Unlike California LCFS and the Oregon CFP, currently no reporting limit for span between biomethane injection and claim

Reporting biomass-derived fuels: OAR 340-215-0044(5)

Emissions calculations

$$CO_2 = 1 \times 10^{-3} \sum Fuel * HHV * EF \text{ (Eq. NN-1)}$$

CO_2 = Annual CO_2 emissions that would result from complete combustion or oxidation of the total volume of natural gas delivered to all end users (metric tons)

Fuel = Total volume of natural gas delivered to all end users (Mscf)

HHV = Higher heating value of supplied fuel (MMBtu/Mscf)

EF = CO_2 emission factor of the delivered fuel (kg / MMBtu)

40 C.F.R part 98, subpart NN

Emissions calculations

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * \text{Fuel} * \text{HHV} * \text{EF} \text{ (Eq. C-8)}$$

CH_4 or N_2O = Annual CH_4 or N_2O emissions that would result from complete combustion of the total volume of natural gas delivered to all end users (metric tons). Convert to CO_2e using global warming potential from Table A-1 (40 C.F.R. part 98, subpart A)

Fuel = Volume of natural gas delivered (Mscf)

HHV = Higher heating value of supplied fuel (MMBtu/Mscf)

EF = Emission factor of the delivered fuel (kg CH_4 or N_2O per MMBtu)

40 C.F.R part 98, subpart C

Emission calculations

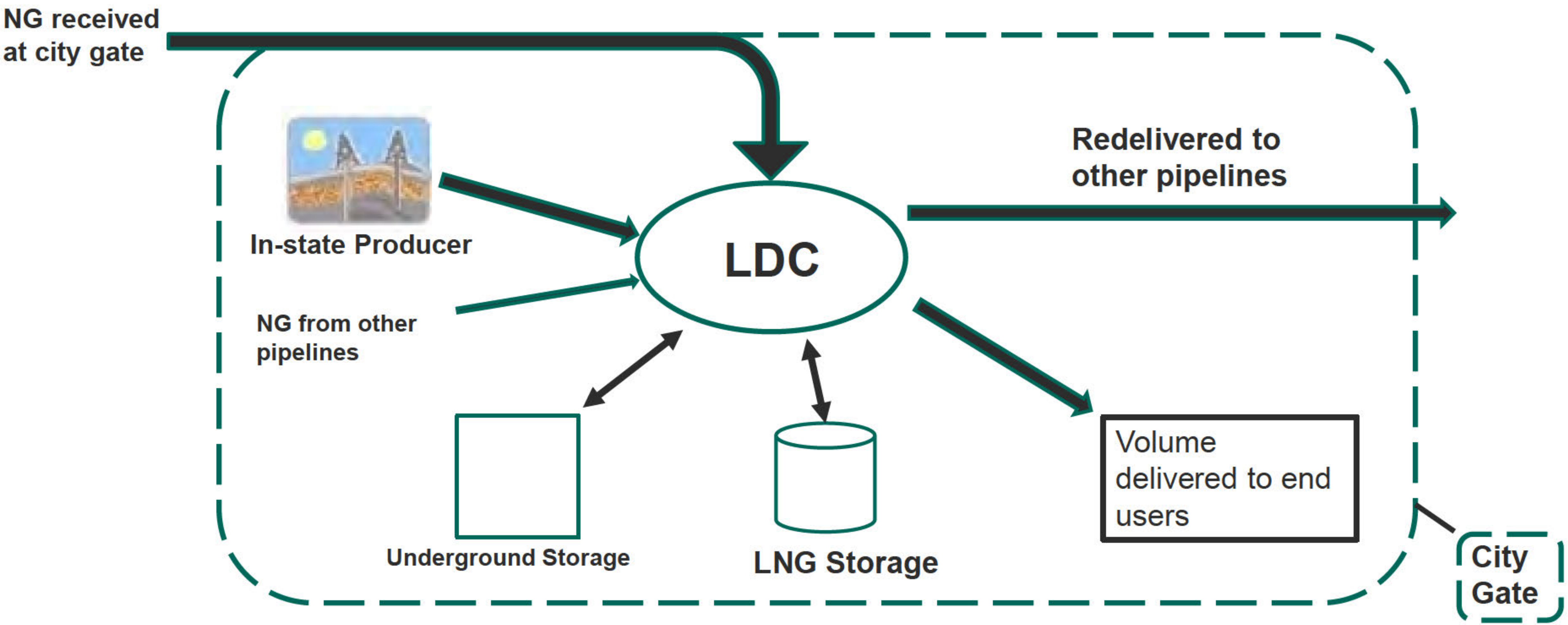
May use either the default or reporter values for:

- Higher heating value
- Emission factor

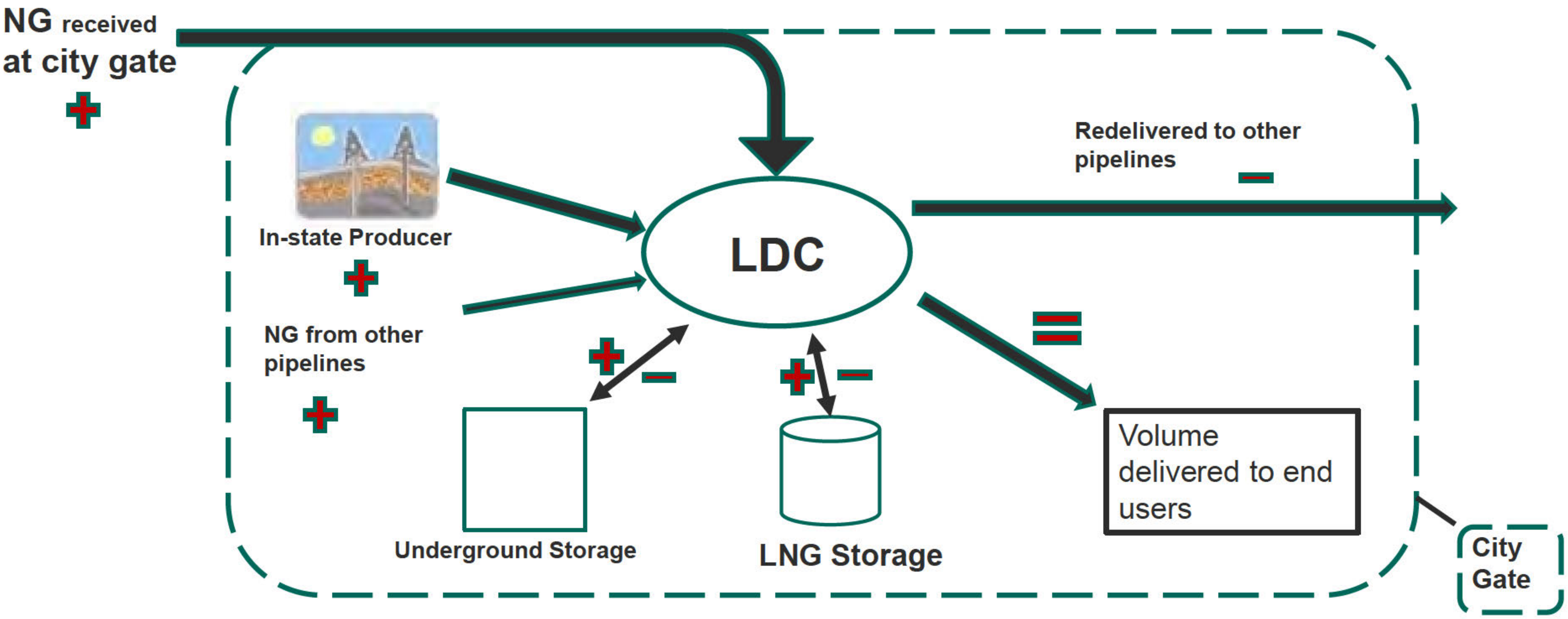
Must follow requirements in 40 CFR § 98.404 and provide data used to calculate these values if requested by DEQ

Natural gas supplier regulation: OAR 340-215-0115

LDC volume calculation



LDC volume calculation



Agenda

1. Sector overview
2. Natural gas supplier reporting requirements
3. **Verification process**
4. Reporting examples

Verification process

- HHV measured by the LDC or the interstate company?
- Measurement frequency?

Verification process

- No exempt meters, but financial meters lower risk

- How did the supplier compile this data? Can they recreate the query?

- Contract, invoices, nomination reports, chain of custody for environmental attributes, etc.
- No double counting
- Should be considered high risk and reviewed accordingly

Agenda

1. Sector overview

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3. Verification process

4. Reporting examples

Example 1 - LDC volume calculation

Volume received at city gate = 100,000,000 Mscf

Volume added to storage = 20,000,000 Mscf

Volume removed from storage = 25,000,000 Mscf

Volume redelivered to other pipelines = 5,000,000 Mscf

Volume received not at city gate = 1,000,000 Mscf

Volume delivered to power plants = 75,000,000 Mscf

Volume delivered to other large end users = 8,000,000 Mscf

Volume delivered to other end users = 18,000,000 Mscf

Calculate the total volume (Mscf) required to be reported and the total emissions (CO2e).

Assume default HHV and EFs

Natural gas supplier regulation: OAR 340-215-0115

Example 1 - Solution

Volume received at city gate = 100,000,000 Mscf

Volume added to storage = 20,000,000 Mscf

Volume removed from storage = 25,000,000 Mscf

Volume redelivered to other pipelines = 5,000,000 Mscf

Volume received not at city gate = 1,000,000 Mscf

Volume delivered to power plants = 75,000,000 Mscf

Volume delivered to other large end users = 8,000,000 Mscf

Volume delivered to other end users = 18,000,000 Mscf

Total end user deliveries =

75,000,000 Mscf
+ 8,000,000 Mscf
+ 18,000,000 Mscf

= 101,000,000 Mscf

Natural gas supplier regulation: OAR 340-215-0115

Example 1 - Solution

Volume received at city gate = 100,000,000 Mscf	+	**Total receipts (+) =**
Volume added to storage = 20,000,000 Mscf	−	100,000,000 Mscf
Volume removed from storage = 25,000,000 Mscf	+	+ 25,000,000 Mscf
Volume redelivered to other pipelines = 5,000,000 Mscf	−	+ 1,000,000 Mscf
Volume received not at city gate = 1,000,000 Mscf	+	**= 126,000,000 Mscf**
Volume delivered to power plants = 75,000,000 Mscf	−	
Volume delivered to other large end users = 8,000,000 Mscf	−	
Volume delivered to other end users = 18,000,000 Mscf	−	

Natural gas supplier regulation: OAR 340-215-0115

Example 1 - Solution

Volume received at city gate = 100,000,000 Mscf +

Volume added to storage = 20,000,000 Mscf −

Volume removed from storage = 25,000,000 Mscf +

Volume redelivered to other pipelines = 5,000,000 Mscf −

Volume received not at city gate = 1,000,000 Mscf +

Volume delivered to power plants = 75,000,000 Mscf −

Volume delivered to other large end users = 8,000,000 Mscf −

Volume delivered to other end users = 18,000,000 Mscf −

Total deliveries (-) =

20,000,000 Mscf
+ 5,000,000 Mscf
+ 75,000,000 Mscf
+ 8,000,000 Mscf
+ 18,000,000 Mscf

= 126,000,000 Mscf

Natural gas supplier regulation: OAR 340-215-0115

Example 1 - Solution

Volume received at city gate = 100,000,000 Mscf	+
Volume added to storage = 20,000,000 Mscf	−
Volume removed from storage = 25,000,000 Mscf	+
Volume redelivered to other pipelines = 5,000,000 Mscf	−
Volume received not at city gate = 1,000,000 Mscf	+
Volume delivered to power plants = 75,000,000 Mscf	−
Volume delivered to other large end users = 8,000,000 Mscf	−
Volume delivered to other end users = 18,000,000 Mscf	−

Receipts = Deliveries

All gas accounted for

Natural gas supplier regulation: OAR 340-215-0115

Example 1 - Solution

Volume received at city gate = 100,000,000 Mscf

Volume added to storage = 20,000,000 Mscf

Volume removed from storage = 25,000,000 Mscf

Volume redelivered to other pipelines = 5,000,000 Mscf

Volume received not at city gate = 1,000,000 Mscf

Volume delivered to power plants = 75,000,000 Mscf

Volume delivered to other large end users = 8,000,000 Mscf

Volume delivered to other end users = 18,000,000 Mscf

Total deliveries = 101,000,000 Mscf

<u>Emissions</u>

$\mathbf{CO_2} = 1\times10^{-3} \sum \text{Fuel} * \text{HHV} * \text{EF}$

$\mathbf{CO_2} = 1\times10^{-3}$
* (101,000,000 Mscf)
* (1.026 MMBtu / Mscf)
* (53.06 kg CO_2 / MMBtu)

= 5,498,396 MT CO_2

Natural gas supplier regulation: OAR 340-215-0115

Example 1 - Solution

Volume received at city gate = 100,000,000 Mscf

Volume added to storage = 20,000,000 Mscf

Volume removed from storage = 25,000,000 Mscf

Volume redelivered to other pipelines = 5,000,000 Mscf

Volume received not at city gate = 1,000,000 Mscf

Volume delivered to power plants = 75,000,000 Mscf

Volume delivered to other large end users = 8,000,000 Mscf

Volume delivered to other end users = 18,000,000 Mscf

Total deliveries = 101,000,000 Mscf

Emissions

CH_4 = 2,591 MT CO_2e
N_2O = 3,088 MT CO_2e

Total = CO_2 + CH_4 + N_2O

Total = 5,498,396 + 2,591 + 3,088

Total = 5,504,074 MT CO_2e

Natural gas supplier regulation: OAR 340-215-0115

Example 2 - Marketers

Natural gas supplier regulation: OAR 340-215-0115

Example 2 - Solution

Incorrect

Marketer volumes should be included within total delivered volume

Natural gas supplier regulation: OAR 340-215-0115

Example 3 – Large end users

Company Name	Meter Number	DEQ Source ID	Volume of Gas (Mscf)
Potato Company - Portland Plant	56458	26-0001	500,000
Potato Company - Bend Plant	62584	13-1234	700,000
Potato Company - Medford Plant	65878	05-0002	900,000
Portland General Electric - Carty	245	25-0002	10,000,000
Portland General Electric - Coyote Springs	258	25-0003	12,000,000

And submitted the following large end user data:

Company Name	Meter Number	DEQ Source ID	Volume of Gas (Mscf)
Potato Company	56458	26-0001	2,100,000
Portland General Electric	245	25-0002	22,000,000

Is this reporting accurate?

Natural gas supplier regulation: OAR 340-215-0115

Example 3 – Large end users

Company Name	Meter Number	DEQ Source ID	Volume of Gas
Potato Company - Portland Plant	56458	26-0001	500,000
Potato Company - Bend Plant	62584	13-1234	700,000
Potato Company - Medford Plant	65878	05-0002	900,000
Portland General Electric - Carty	245	25-0002	10,000,000
Portland General Electric - Coyote Springs	258	25-0003	12,000,000

And submitted the following large end user data:

Company Name	Meter Number	DEQ Source ID	Volume of Gas
Potato Company	56458	26-0001	2,100,000
Portland General Electric	245	25-0002	22,000,000

No: Large end users should be reported and verified at the facility level, not parent company

Natural gas supplier regulation: OAR 340-215-0115

This concludes this presentation

For questions, please contact us:

3PVerify@deq.state.or.us

Thank you for attending!

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PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Anna K. Chittum

LEXINGTON RNG PROJECT
EXHIBIT 2103

June 6, 2022

NW Natural®

250 SW Taylor Street
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503-226-4211
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October 25, 2021

VIA ELECTRONIC MAIL

Department of Environmental Quality
Office of Greenhouse Gas Programs
700 NE Multnomah Street, Suite 600 Portland
Oregon 97232

RE: NW Natural Comments – Climate Protection Program Draft Rule

Dear Oregon Department of Environmental Quality ("DEQ"),

NW Natural appreciates the opportunity to provide public comments on DEQ's proposed Climate Protection Program ("CPP" or "Draft Rule").

NW Natural is committed to helping Oregon transition to a low-carbon, renewable-energy future while ensuring energy reliability for all Oregonians. Already, we are ahead of the target we established in 2016 to meet our 30% carbon savings goal by 2035, based on 2015 emissions associated with our operations and the use of our product by customers.[1] We also have established "Destination Zero," which lays out our pathway to achieve a carbon-neutral future by 2050.[2] NW Natural's confidence that its emission reduction targets can and will be met is bolstered by its directional alignment with the state's decarbonization goals.

NW Natural recognizes that our company and our customers play a key role in implementing climate change solutions. A report by the premier environmental consultant Energy and Environmental Economics outlines how NW Natural's pipeline system can be instrumental in achieving deep decarbonization in our region in an affordable and reliable manner.[3] Additionally, a diverse set of solutions is critically important to address the climate crisis, as the world has a limited amount of critical minerals that wind and solar energy projects rely on.[4]

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[1] NW Natural Holdings, *2020 Environmental, Social and Governance (ESG) Report*, 18 (Aug. 2, 2021), available for download at https://www.nwnatural.com/about-us/the-company/sustainability.
[2] *Id.* at 24.
[3] Energy and Environmental Economics, *Pacific Northwest Pathways to 2050*, (Nov. 2018), https://www.ethree.com/wp-content/uploads/2018/11/E3_Pacific_Northwest_Pathways_to_2050.pdf.
[4] *See, e.g.,* International Energy Agency, *The Role of Critical Minerals in Clean Energy Transitions*, 11–12 (May 2021), https://iea.blob.core.windows.net/assets/24d5dfbb-a77a-4647-abcc-667867207f74/TheRoleofCriticalMineralsinCleanEnergyTransitions.pdf ("The prospect of a rapid increase in demand for critical minerals—well above anything seen previously in most cases—raises huge questions about the availability and reliability of supply. . . . Without broad and sustained efforts to improve environmental and social performance, it may be challenging for consumers to exclude minerals produced with poor standards as higher-performing supply chains may not be sufficient to meet demand.").

NW Natural delivers more energy in Oregon than any other utility,[5] and yet our residential and commercial customers' use of natural gas in homes and businesses accounts for only 6 percent of Oregon's greenhouse gas ("GHG") emissions.[6] We know we can continue to shrink this emissions percentage and have begun to do so. Currently, NW Natural is partnering with BioCarbN to convert methane from Tyson Foods facilities into renewable natural gas ("RNG") to heat homes and businesses.[7] And, in 2020, we also began testing a 5% hydrogen blend at our state-of-the-art training facility in Sherwood, Oregon.[8] These efforts are the beginning of decades of future clean energy innovation to come.

Furthermore, we have made exceptional investments in resources to ensure we operate one of the tightest, most modern gas systems in the nation. Among U.S. natural gas utilities, NW Natural consistently has one of the lowest ratios of leaks per mile of pipe.[9] In 2020 alone, we performed safety inspections on our transmission system at nearly three times the rate required by federal and state regulations.[10] We believe a proactive and prevention-based approach is the foundation of a safe and environmentally responsible system.

Guided by our company's energy expertise and commitment to decarbonization, NW Natural offers the following comments in support of DEQ finalizing a program that maximizes GHG reductions and ensures energy accessibility for all Oregonians.

Introduction

NW Natural is prepared to and can comply with the CPP. We support decarbonization of the gas sector and already have begun to transform our system. However, we need support to do more, and faster. The CPP, coupled with the implementation of SB 98,[11] presents an opportunity to accelerate climate solutions, but only if the CPP maximizes *compliance certainty* so that we can make long-term, durable clean energy investments on behalf of our customers, and take advantage of cost-effective emission reduction opportunities.

The CPP establishes a cap-and-reduce program that distributes compliance instruments to covered fuel suppliers at no cost.[12] The emissions cap and corresponding compliance instruments distributed to covered fuel suppliers, which include NW Natural, will gradually but meaningfully decline each year through 2050. To meet their compliance obligations, covered fuel suppliers can directly reduce their GHG emissions, lower the carbon intensity of their fuel, trade compliance instruments with other

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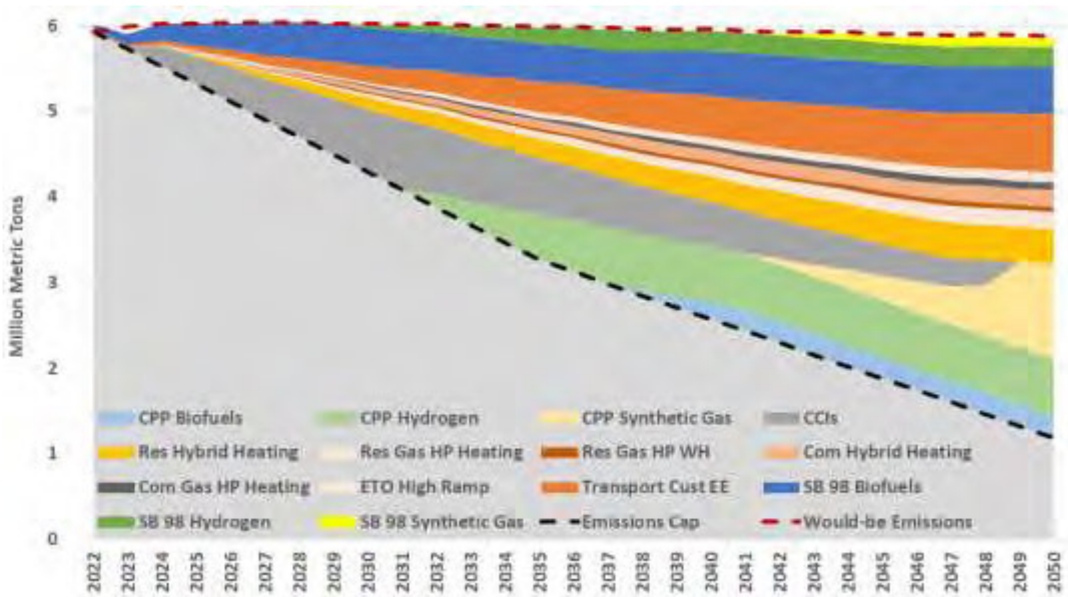
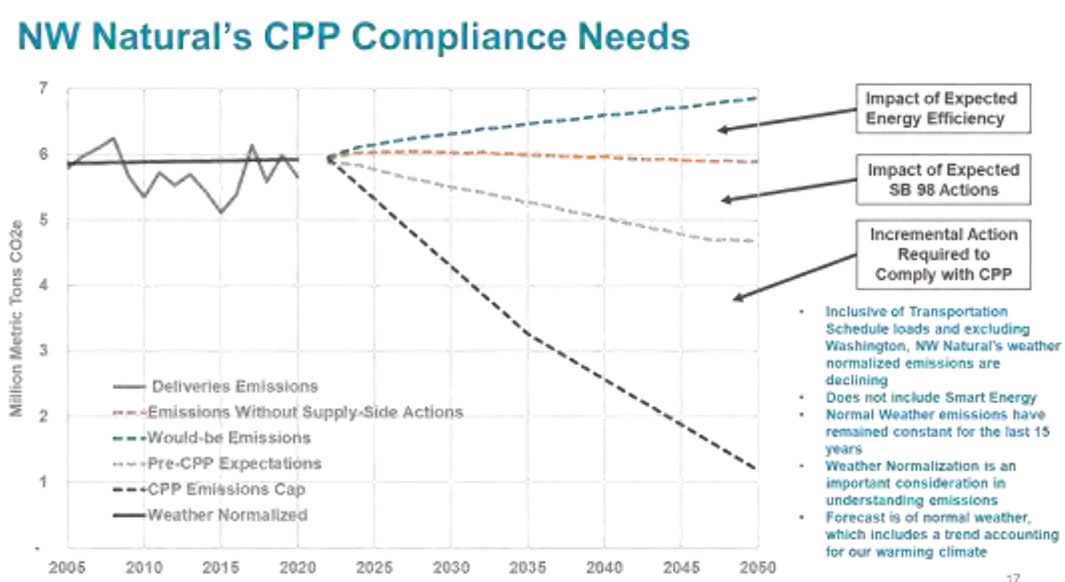
[5] Oregon Public Utility Commission, *2015 Oregon Utility Statistics Statbook*.
[6] State of Oregon Department of Environmental Quality, *In-Boundary GHG Inventory Preliminary 2015 Figures.*
[7] NW Natural Holdings, *2020 Environmental, Social and Governance (ESG) Report*, at 25.
[8] *Id.* at 27.
[9] *Id.* at 10.
[10] *Id.* In 2020, NW Natural had a ratio of approximately 0.80 leaks per 100 miles of distribution pipeline. For comparison, the 2019 industry average was 7.65 leaks per 100 miles, based on U.S. Department of Transportation Annual Report data for natural gas operators reporting more than 7,000 miles of distribution main.
[11] SB 98 requires the PUC to implement rules for a program that sets voluntary RNG procurement targets for Oregon gas utilities, with a target of 30% of gas utilities' portfolios consisting of RNG by 2045. NW Natural supported SB 98, and in the coming year, 2% of our portfolio will consist of renewable fuels.
[12] The CPP's Best Available Emissions Reduction ("BAER") provisions for stationary sources do not apply to NW Natural and are therefore omitted from this rule summary.

covered fuel suppliers, or obtain additional compliance instruments by funding Community Climate Investment ("CCI") projects administered by DEQ.

NW Natural has a plan in place to meet the emission reductions set out in the Draft Rule. As we recently explained to the Oregon Public Utilities Commission ("PUC"), NW Natural plans to utilize a variety of strategies to achieve CPP compliance, including expanding production of RNG and hydrogen and supporting incremental demand reduction.[13] We look forward to working with DEQ and PUC to make these modeled reductions, shown below, a reality.





[13] NW Natural, *Re: UM 2178, Natural Gas Fact-Finding Per Executive Order 20-04, NW Natural's Compliance Modeling Presentation – Updated*, (Sept. 15, 2021), https://edocs.puc.state.or.us/efdocs/HAH/um2178hah12139.pdf.

However, NW Natural believes the effectiveness of the CPP can be further improved to achieve actual, meaningful, and verifiable emissions reductions at a lower cost without jeopardizing the reliability and resiliency of the energy system. In particular, we ask that DEQ consider (1) clarifying that "covered emissions" do not include GHG emissions from natural gas consumed in Oregon that are negated by biomass-derived fuels contractually purchased on behalf of Oregonians; (2) including an offset program to supplement our long-term, infrastructure-focused compliance plans; and (3) adopting measures protective of customers, such as a compliance exemption for unforeseen events and a cost cap to prevent program costs from ever becoming unexpectedly excessive.

Finally, NW Natural continues to support the promulgation of a legislative solution for decarbonization. We resolutely supported Oregon's cap and trade bill because it would have equipped DEQ with the tools that it needed to transform Oregon's energy system. However, given that such statutory authority is lacking, DEQ has had to unfortunately grapple with how to promulgate a novel rule using its existing authorities.[14] We remain concerned about the disconnect between DEQ's current authorities and the measures needed to design and implement regulatory programs that meet the urgent emissions reductions and equity challenges posed by climate change.

We are grateful for the extensive stakeholder feedback process DEQ has conducted. There is no alternative to the renewable energy transition, which is why NW Natural has long supported reducing GHG emissions and wants to contribute to making the CPP as effective as possible.

<u>Comments on the Draft Rule</u>

A. Certainty Fosters Transformative Investments And Reduces Risks For Customers.

Regulatory certainty is crucial for covered fuel suppliers to effectively comply with the CPP. Such certainty holds particular importance for public utilities like NW Natural, which must plan years to in advance to ensure that both customer demand and its existing GHG reduction goals achieved via transformative clean energy investments are met.[15] Similarly, program provisions that provide increased certainty regarding program costs and energy reliability will benefit all Oregonians.

1. The CPP appropriately exempts biomass-derived fuels from covered emissions.

NW Natural appreciates the exemption of biomass-derived fuels from covered emissions under the CPP.[16] Biomass fuels such as RNG play a crucial role in our company's deep decarbonization plan, and they will be important for decarbonization nationwide.[17] By exempting biomass-derived fuels from the

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[14] *See, e.g.,* DEQ, *Program Options to Cap and Reduce Greenhouse Gas Emissions: Final Report*, 7–9 (June 2020); *see also* Oregon Department of Justice, *Memorandum – Authority of the Environmental Quality Commission to Regulate Greenhouse Gases Under Current Oregon Law*, 11–14 (Oct. 11, 2019).

[15] *See* OAR 860-027-0400 (summarizing Integrated Resource Plan filing requirements).

[16] DEQ, *Notice of Proposed Rulemaking: Greenhouse Gas Emissions Program 2021 Rulemaking, Climate Protection Program,* 105 (Aug. 5, 2021) ("Draft Rule").

[17] As GHG-reducing solutions continue to emerge, we encourage DEQ to undertake subsequent rulemakings to address how the GHG reporting rule can best align with the CPP and emerging technologies. NW Natural supports the creation of GHG accounting frameworks to account for emissions reduced via hydrogen and carbon capture technologies, including for carbon capture used at customer facilities to reduce emissions. We would welcome the opportunity to meet with DEQ regarding these topics for further discussion.

program cap, DEQ has provided a viable pathway for fuel suppliers to lower the carbon intensity of their fuels. Furthermore, embracing this technology-neutral approach to addressing climate change is critical to ensuring a reliable energy system.[18]

2. The CPP should further clarify the scope of covered emissions.

NW Natural urges DEQ to amend OAR 340-271-0110(3)(b)(B) to clarify that "covered emissions" do not include GHG emissions from natural gas consumed in Oregon that are negated by biomass-derived fuels contractually purchased on behalf of Oregonians, regardless of whether the fuels are tracked to specific end users. Much like renewable electricity, RNG is purchased on behalf of customers, but the actual molecules are not guaranteed to arrive at a specific location. Nevertheless, their generation and addition to the pipeline system results in the displacement of traditional natural gas and a reduction in GHG emissions.

Clarifying that RNG purchased to comply with the CPP does not have to be tracked to the specific end user of where the RNG is delivered would align the book-and-claim accounting of multiple other federal and state programs, including programs in Oregon. For example, DEQ includes this type of book-and-claim accounting in its Clean Fuels Program.[19] DEQ also advocated that the PUC use book-and-claim accounting in the PUC's RNG rulemaking under SB 98.[20] Furthermore, this would align with the approach taken in Oregon's renewable portfolio standard program ("RPS"). The RPS recognizes renewable energy credits ("RECs") and thermal renewable energy credits ("T-RECs") generated by facilities in 14 different states and includes Mexico and Canada. Since its implementation, Oregon's RPS program has encouraged renewable electricity generation—including from biomass—both within the state and regionally. The California Low Carbon Fuel Standard and the federal Renewable Fuel Standard also utilize this approach.[21]

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[18] Notably, relying on solar or wind energy alone is a risky strategy, especially because, according to the International Energy Agency, "the data shows a looming mismatch between the world's strengthened climate ambitions and the availability of critical minerals that are essential to realising those ambitions." International Energy Agency, *Clean energy demand for critical minerals set to soar as the world pursue net zero goals*, (May 5, 2021), https://www.iea.org/news/clean-energy-demand-for-critical-minerals-set-to-soar-as-the-world-pursues-net-zero-goals.

[19] *See* OAR 340-253-0400.

[20] In Order 20-227, which adopted PUC rules under SB 98, the PUC wrote, "DEQ also addressed the book and claim accounting function of the proposed rules, which allows electronic tracking of RTCs [Renewable Thermal Credits] as of injection into a common carrier pipeline, with no need to track the physical gas. The approach is consistent with how RNG is tracked in the Oregon Clean Fuels Program, as well as in the California Low Carbon Fuel Standard, and the federal Renewable Fuel Standard. DEQ noted that the flexibility of the approach helps the development of projects that would otherwise be uneconomic if physical delivery was required." PUC, *Order 20-227*, 5, (July 16, 2020), https://apps.puc.state.or.us/orders/2020ords/20-227.pdf. *See also* DEQ, *Comment Letter to PUC*, (May 6, 2020), https://edocs.puc.state.or.us/efdocs/HAC/ar632hac163214.pdf.

[21] California Air Resources Board, *Low Carbon Fuel Standard (LCFS) Guidance 19-05*, (revised Oct. 2019), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-05.pdf; EPA, *Renewable Fuel Standard Program*, https://www.epa.gov/renewable-fuel-standard-program (last visited Oct. 20, 2021).

Thus, adopting a consistent book-and-claim accounting approach for biomass-derived fuels in this rulemaking would allow the CPP to have a similarly wide-spread and significant emissions reduction impact.[22]

3. The CPP should include an offset program.

NW Natural urges DEQ to allow offsets to be utilized as a CPP compliance mechanism. The option to utilize offsets would equip covered entities with a tool to smooth out potential cost-spikes in their long-term compliance plans; for example, allowing gas utilities to support reductions in other areas of the economy, as more RNG projects develop, would meet the CPP's goals of reducing emissions while keeping costs reasonable.

Offset programs have long been a foundational component of emission reduction programs that cap emissions. In fact, most carbon policies that implement caps on GHG emissions allow for some use of carbon offsets by covered parties, including offsets that occur outside of the state that the cap program covers.[23] While an important tool in itself, the CCI program is too nascent and uncertain to play the same role in allowing covered entities to deploy real, measured, and verified emissions reductions *on demand*, and at the least cost for Oregonians.

GHG-reducing technologies and projects are rapidly advancing. To be effective, the CPP must allow covered entities to take advantage of cost-effective mechanisms for reducing emissions—wherever and however they occur. Including a true offset program in the CCP would align with DEQ's own modeling study, conducted by ICF, which found that "compliance flexibility will be important to achieving ambitious greenhouse gas reduction goals."[24] The study also highlighted that "[e]nergy costs may be higher in scenarios with greater emissions reduction caps and less compliance flexibility."[25] Therefore, having an offset program would help to lower the cost of reducing emissions while providing even more emissions reduction opportunities.[26]

NW Natural's existing voluntary offset program, Smart Energy, provides a proven mechanism for offsetting emissions from energy consumed in Oregon and could be readily adapted to and recognized by the final CPP. Through Smart Energy, NW Natural customers have offset over 1.5 million metric tons of

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[22] Additionally, NW Natural would support DEQ initiating a separate rulemaking to amend the GHG reporting rule to align with the proposals in this section.

[23] For example, California's cap and trade program allows offsets to be used for up to 6% of a covered entity's compliance obligation from 2026-2030. 17 C.C.R. § 95854. The Transportation and Climate Initiative Program Model Rule, which at least three states and D.C. plan to adopt, also includes offset provisions. Transportation and Climate Initiative Program, *Draft Model Rule*, 109–116 (Mar. 1, 2021), https://www.transportationandclimate.org/sites/default/files/TCI-P-Draft-Model-Rule-March-2021.pdf.

[24] ICF and DEQ, *Modeling Study on Program Options to Reduce Greenhouse Gas Emissions*, 7 (Aug. 2021), https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/GHGCR2021MSsummary.pdf (emphasis added).

[25] *Id.* at 20 (emphasis added).

[26] For more on the importance of carbon offsets in contributing to emissions reductions, *see* Environmental Defense Fund, *Carbon Offsets – When Done Right – Can Reduce Emissions and Support the Paris Agreement: EDF and ENGIE Impact*, (Dec. 17, 2020), https://www.edf.org/media/carbon-offsets-when-done-right-can-reduce-emissions-and-support-paris-agreement-edf-and-engie.

CO_2. These offsets represent real emissions reductions verified by The Climate Trust.[27] Smart Energy is in place and delivering emission reductions today. Inclusion of an offset program in the CPP would incentivize even greater verifiable emissions reductions.

4. The CPP should include a cost cap to protect customers.

NW Natural recommends that the CPP include a cost cap to prevent program costs from ever becoming unexpectedly excessive. Controlling costs for the utility is essential because energy is a public good. For this reason, cost caps are a routinely applied protection embedded in other current carbon regulations in states such as Washington and California.[28]

Not including a cost cap for a program that directly and indirectly will cover large swaths of Oregon's economy and populace fails to provide commonsense protections for Oregon businesses and residents.[29] A cost cap ensures that there is a braking mechanism in case any unintended consequences occur, as the CPP is a completely new and untested program.[30] The new and uncertain nature of the program is likely to lead to dramatic swings in the price of traded compliance instruments, which in turn could have the unintended consequence of causing compliance costs to spike without a remedy to stop these skyrocketing costs. Not having a cost containment mechanism could have a profoundly negative impact on Oregon's economy overall and on sectors that are either directly or indirectly covered by the CPP.

Furthermore, cost caps play an important role in guarding against unintended consequences that may unfairly burden low-income communities. While the recently passed Energy Affordability Act may also help protect these communities, the PUC has yet to promulgate regulations implementing this Act, and its tools for doing so are not unlimited.[31] Thus, by including a cost cap, DEQ will also further promote protections for low-income communities in the final rule, thereby helping fulfill the agency's stated goal to prioritize equity.[32]

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[27] NW Natural, *Smart Energy Frequently Asked Questions.*, https://www.nwnatural.com/about-us/carbon-offset-program/smart-energy-faqs (last visited Oct. 20, 2021).

[28] Washington SB 5116, Sec. 6(3)(a), (2019), http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5116-S2.SL.pdf?q=20210822161309; Center for Climate and Energy Solutions, *California Cap and Trade*, https://www.c2es.org/content/california-cap-and-trade/ (last visited Sept. 23, 2021).

[29] Unlike companies in other sectors, public utilities like NW Natural have a statutory duty to "furnish adequate and safe service at reasonable rates" and to refrain from "mak[ing] or giv[ing] undue or unreasonable preference or advantage to any particular person or locality." ORS 757.020, 757.325.

[30] A cost cap would also help ensure that public utilities receive a reasonable rate of return to guarantee the financial sustainability of the public services they offer. *See Bluefield Water Works Co. v. Public Serv. Comm'n*, 262 U.S. 679, 690 (1923) ("Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment."); *Smyth v. Ames*, 169 U.S. 466, 475 (1898) ("What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.").

[31] The Energy Affordability Act, for example, just provides an option for utilities to subsidize rates for low-income customers, but it does not grant utilities additional funds for providing these subsidies.

[32] If DEQ does not adopt a cost cap, NW Natural requests to meet with DEQ about other potential measures to shield low-income customers from unanticipated sharp increases in prices.

5. The CPP should include a compliance exemption for unforeseen events.

NW Natural recommends that DEQ amend the CPP to include a compliance exemption for unforeseen events. This compliance exemption would temporarily exempt a public utility from compliance if the utility ever had to unexpectedly choose between providing energy services and complying with the CPP in any given year. For example, this could become an issue if Oregon experiences extremely cold weather.

Potential options for protecting against unforeseen events include, but are not limited to, leveraging existing planning and ratemaking methodologies to adjust emissions obligations using weather normalization.[33] Alternatively, DEQ could create a petition process whereby the gas utility applies for a compliance exemption due to unforeseen events for which it was not possible to reasonably plan. Notably, Oregon electric utilities already have exemptions to compliance from statutory GHG emission goals where such compliance would pose unforeseen issues. The CPP should simply do the same for gas utilities and their customers.

6. Safety valves mitigate the tensions between DEQ and PUC authorities.

Without the above safety valve mechanisms of a cost cap and a compliance exemption for unforeseen events, DEQ risks creating an irreconcilable conflict between DEQ's and the PUC's statutory authorities. Oregon's public utilities are statutorily required to furnish "adequate and safe service" to consumers in a nondiscriminatory manner at rates that are "reasonable and just."[34] As drafted, the CPP could impermissibly intrude on gas utilities' execution of these statutorily required duties because the program—by design—caps the provisions of natural gas without a meaningful safety valve to account for unforeseen events.

While NW Natural has a pathway to compliance,[35] even the most careful planning may not accurately account for all eventualities. Under the CPP as currently drafted, if customer demand for natural gas exceeds the company's available compliance credits due to a series of unexpected winter storms,[36] NW Natural could be forced to choose between fulfilling its statutory duty of providing necessary energy services and incurring $12,000+ fines for every unpermitted metric ton of CO2e released.[37] Such conflict is an unreasonable and absurd result.

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[33] Although a three-year compliance period is more appropriate for this program than a single year in order to account for such unexpected events, it is still unsatisfactory for the volatility faced by the natural gas utilities. While it is possible to plan for deviations from normal weather expectations, there is also a cost to holding more compliance instruments than is required to protect against possible weather-based deviations. Three years is not a long enough period to address unforeseen circumstances.

[34] ORS 757.020, 757.325.

[35] *See* Introduction.

[36] Even as climate change is causing global average temperatures to rise, it has also been linked to unusually cold weather patterns in the United States. *See, e.g.,* Judah Cohen et al., *Linking Arctic variability and change with extreme winter weather in the United States*, Science (Sept. 3, 2021), https://www.science.org/doi/10.1126/science.abi9167.

[37] *Compare* ORS 757.020 *with* Draft Rule, at 65–67.

Oregon courts have "frequently held that a statutory construction which would lead to unreasonable or absurd results should be avoided."[38] To uphold the CPP as drafted, a court would have to find that DEQ has *authority* to require a public utility to comply with the CPP's regulatory requirements even if it would mean violating the utility's statutory obligations to provide gas service. Adopting the safety valves recommended by NW Natural would mitigate the statutory tensions embedded by the approach in the Draft Rule.

B. CCI Program Success Hinges On Verified Reductions And Available Credits.

DEQ should amend the CCI program to ensure that it induces emission reductions and spurs investments in low-income communities. For fuel suppliers, the primary mandates of the CPP are to reduce end-user emissions through efficiency measures and the carbon intensity of their fuels through low- or no-carbon fuels—and NW Natural already has taken steps to begin this process. The CPP also provides through the CCI program an option for fuel suppliers to meet a limited portion of the cap requirements through supporting emission reduction projects that benefit low-income communities. Although CCI credits are only a small component of NW Natural's CPP compliance plan, it is critical for the overall integrity of the CPP that the CCI program produce ample projects with verifiable emissions reductions.

1. GHG emission reduction accounting for CCI projects should be accurate.

NW Natural urges DEQ to adopt an accurate and transparent methodology for tracking CCI emission reductions.[39] Accurate and transparent GHG accounting methodologies are the bedrock of flexible compliance mechanisms because they allow companies to better evaluate the benefits of investing in potential projects and opportunities. Proper carbon accounting is key for tracking progress towards the goals of the cap, the distribution of compliance instruments to covered entities, and the success or shortcomings of the CCI program. Without accurate accounting, it will be difficult to measure the CPP's true impact.

Because emissions accounting is a highly technical issue, NW Natural supports DEQ initiating technical workshops that aim to arrive at an accurate, transparent, and verifiable approach. Topics for discussion should include (1) appropriate GHG accounting guidelines for CCI entities, (2) safeguards to prevent double-counting of emissions reductions, and (3) quantifying emissions from leakage, among other GHG accounting topics.[40] Technical workshops focused solely on the topic of GHG accounting are likely to result in a GHG accounting methodology that has credibility and is readily implementable by CCI entities. NW Natural would welcome the opportunity to participate in and contribute to such as process.

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[38] *Peters v. McKay*, 195 Or. 412, 440 (1951).

[39] NW Natural is not alone in raising this concern. PUC staff also raised this issue in PUC Docket No. UM 2178: "Community Climate Investments (CCI) are a CPP compliance instrument. However, it is not currently clear to PUC how the emissions associated with these projects will be quantified and verified. PUC staff would like to understand the role CCIs play in accomplishing compliance with emissions reduction and what emissions reduction options become more viable if they are not part of a solution set." PUC, *Natural Gas Fact Finding Compliance Modeling Proposed Sensitivities,* 2 (Aug. 4, 2021), https://edocs.puc.state.or.us/efdocs/HAH/um2178hah164359.pdf.

[40] Illustrations demonstrating the need for robust carbon accounting to be included in or issued in parallel to the final CPP are described in Appendix A of this letter.

2. Each regulated sector should have a separate CCI program.

NW Natural continues to assert that in order to best align the reduction of emissions from the source of those emissions, the transportation sector and the natural gas utility sector should have separate CCI programs that keep separate carbon and economic accounting books. Customers within each sector, who will bear the financial burden of this program, should not be forced to cross-subsidize other sectors via CCI funds. This would not only make the program easier to administer, but also would ensure greater accountability and that the objectives of cost containment, GHG emissions reductions, and equity are achieved within the particular covered sector.

The CCI fund of each sector should reflect projects that reduce emissions emitted from that sector and should not inflict additional financial burdens on the customers paying into these funds. This also ensures that those paying for compliance receive the benefits of GHG reductions, cost containment, and equity. For example, a project that leads to a substantial reduction in particulate matter might not be appropriate for funds from natural gas utility customers, given that natural gas combustion emits far less particulate matter than the combustion of most transportation fuels.

3. Covered fuel suppliers should be eligible to partner with CCI program entities.

Covered fuel suppliers, like other businesses, can provide valuable support to CCI entities and should therefore be permitted to partner with them. The administrative lift to qualify as a CCI entity and implement CCI projects is substantial. Non-profit entities must submit a detailed application to become a CCI entity, come up with a way of estimating and tracking the GHG emissions reductions that will result from the CCI projects they propose, and submit annual work plan reports to DEQ.[41] As such, CCI entities should be provided with maximum support from both covered and non-covered entities to increase the chance of success for the program.

NW Natural is **not** asking that this adjustment include a potential to benefit financially for the covered fuel suppliers; rather, it only asks for a means of increasing participation and access regarding CCI projects.[42] Excluding covered entities from the ability to partner and share expertise with CCI entities will only serve to limit the amount of CCI projects available for funding and slow the implementation timeline for projects. Therefore, DEQ should alter OAR 340-271-0910 in the Draft Rule to allow covered fuel suppliers to partner with CCI entities.[43]

4. The CCI program should include measures to assure CCI credit availability.

DEQ should reduce the uncertainty regarding the availability of CCI credits by creating a CCI market assurance fund that ensures the availability of verified CCI credits for covered fuel suppliers who choose to utilize them. Doing so would reduce the substantial uncertainty regarding the viability of the CCI program so that covered entities have the option to incorporate CCI credits into their long-term

[41] Draft Rule, at 134–141.
[42] Some examples of beneficial CCI projects could include locally owned RNG facilities that interconnect with the natural gas pipeline delivery system, or the installation of carbon capture devices for stationary sources.
[43] Specifically, DEQ should delete OAR 340-271-0910(2)(b), which states, “A covered entity or any of its related entities may not be a subcontractor and may not receive CCI funds.”

compliance plans. An assurance fund would also help ensure that environmental justice communities receive the benefits of what is currently a program that is not guaranteed to exist.[44]

As proposed, the amount of CCIs available in any given year is highly speculative. Non-profits would have to go through a complex screening process by DEQ, and it is unclear how many nonprofits will have CCI-eligible projects in any given year. Thus, it is possible that there will be a mismatch between the number of CCI projects available and covered fuel suppliers' demand for CCI credits. This is especially true in the early years of the program, when CCI entities will be in the application phase of the process.

A market assurance fund—or other mechanism—would reduce the risks associated with planning for credits to be available. Instead of waiting for CCI entities to propose and then implement projects, covered fuel suppliers would pay DEQ or a single chosen third party directly for CCI credits, and then DEQ or the third party would keep the money in an account that DEQ then grants to CCI-approved projects. This approach would allow DEQ to issue CCI credits in years when not enough CCI projects may be available, and to save up money for more expensive CCI projects in later years. Such an approach also would provide much-needed certainty to CCI entities and environmental justice communities regarding the amount of funding that is available in any given year.

C. Legislative Solutions Will Yield Better Climate Outcomes.

NW Natural continues to support the promulgation of a legislative solution for decarbonization. We resolutely supported Oregon's cap and trade bill because it would have equipped DEQ with the tools needed to transform Oregon's energy system. However, given that such statutory authority is lacking, DEQ has had to unfortunately grapple with how to promulgate a novel rule using their existing authorities.[45] We remain concerned about the disconnect between DEQ's current authorities and the measures needed to design and implement regulatory programs that meet the urgent emissions reductions and equity challenges posed by climate change.

Through legislation, the Oregon Legislative Assembly could equip DEQ with regulatory authorities that would bolster the underpinnings of the CPP, including the:

- **Authority to regulate non-emitting entities**. DEQ relies on its air permitting authority to regulate gas utilities like NW Natural.[46] While DEQ can regulate a wide variety of sources that emit air contaminants, it should seek legislative authority in order to impose GHG emissions limits on entities that do not actually emit the GHG emissions at issue. In Oregon's air permitting statutes, Chapter 468A, almost every single air contamination source that the legislature gave DEQ

[44] The Draft Rule states that one of the purposes of CCIs are to "[p]romote public health, environmental, and economic benefits for environmental justice communities in Oregon to mitigate impacts from climate change, air contamination, energy costs, or any combination of these." Draft Rule, at 134.
[45] *See, e.g.,* DEQ, *Program Options to Cap and Reduce Greenhouse Gas Emissions: Final Report*, 7–9 (June 2020); *see also* Oregon Department of Justice, *Memorandum – Authority of the Environmental Quality Commission to Regulate Greenhouse Gases Under Current Oregon Law*, 11–14 (Oct. 11, 2019).
[46] Under ORS 468A.025(3), DEQ has the authority to regulate air contaminants, including GHG emissions, from "air contamination sources." OAR 340-200-0020(166) defines "source" as "any building, structure, facility, installation or combination thereof *that emits or is capable of emitting air contaminants to the atmosphere*, is located on one or more contiguous or adjacent properties and is owned or operated by the same person or by persons under common control" (emphasis added).

permission to regulate—such as motor vehicles and solid fuel burning devices—is the *direct cause* of air contaminants.[47] The one exception to this is the regulation of gasoline and diesel fuel suppliers under Oregon's Clean Fuels Program; but unlike with the CPP, the Oregon legislature granted explicit statutory authority for that program.[48]

- **Authority to regulate the carbon intensity of natural gas.** Just as Oregon had to pass a new statute to regulate the carbon intensity of gasoline and diesel fuel sold by suppliers, who do not emit GHGs and therefore cannot be air contamination sources, Oregon needs to pass a new statute to regulate the carbon intensity of natural gas supplied by gas suppliers, who also do not emit GHGs regulated under the CPP. In 2009, Oregon passed HB 2186, a new statute that authorized DEQ to promulgate the Clean Fuels Program, which regulates the carbon intensity of gasoline and diesel fuel sold by fuel suppliers.[49] The reason the Oregon legislature had to pass HB 2186 before DEQ could set a low carbon fuel standard for gasoline and diesel fuel suppliers is that, by merely selling fuel to customers that then burn the fuel, the fuel suppliers themselves do not emit any air contaminants. In other words, the fuel suppliers did not qualify as an "air contamination source" that DEQ could regulate under its existing air permitting authority. Similar action is necessary for DEQ to regulate the carbon intensity of natural gas.[50]

- **Authority to regulate heating equipment emissions in small residences.** Even if natural gas distributors qualified as air contamination sources, DEQ still cannot regulate the natural gas emissions from the appliances that many Oregonian families use to heat their homes and cook their meals. ORS 468A.020(1)(d) specifically exempts from the Oregon air pollution laws "[h]eating equipment in or used in connection with residences used exclusively as dwellings for not more than four families."[51] This more specific statutory provision overrides DEQ's general statutory air pollution permitting authority.[52]

- **Authority to administer an allowance-based program.** The CCI program is an allowance-like program, but it fails to provide the full range of flexibilities and benefits that a statutorily authorized and designed cap and trade program would.[53] This is because DEQ admittedly lacks the authority to charge money for allowances or to spend the money that such allowances generate in other programs.[54] As a result, DEQ has had to propose a novel regulation that

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[47] *See* ORS 468A.360, 468A.465.
[48] *Id.* 468A.266.
[49] *See* OAR 340-253-0000 *et seq.*
[50] In the CPP, DEQ has proposed a low carbon fuel standard for natural gas. DEQ explains: "Furthermore, a covered fuel supplier could supply less fossil fuels in favor of more alternatives, such as biofuels and other clean fuels. This reduces emissions and therefore their compliance obligations in the CPP." Draft Rule, at 19.
[51] A significant portion of the gas NW Natural delivers—constituting roughly one quarter of the emissions from NW Natural's customers—is used to fuel residential heating equipment in dwellings with four families or less.
[52] *See Crawford Fitting Co. v. J. T. Gibbons, Inc.*, 482 U.S. 437, 445, (1987) ("[A] specific statute will not be controlled or nullified by a general one, regardless of the priority of enactment.").
[53] Such benefits include the ability to target funds raised by the sale of allowances to offset rising energy costs (due to compliance with cap and trade programs) in environmental justice communities.
[54] DEQ, *Program Options to Cap and Reduce Greenhouse Gas Emissions: Final Report*, 9 (June 2020) ("DEQ does not believe that the EQC has the authority to auction or otherwise sell rights to emit greenhouse gases. A further complication is that DEQ has no authority to receive or spend auction proceeds.").

attempts to work around its limitations. The CCI program would stand on stronger legal ground if the state legislature specifically authorized DEQ to administer an allowance-based program.

NW Natural urges DEQ to evaluate whether there are changes that can be made to the Draft Rule to further align the CPP with DEQ's current authorities.

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NW Natural thanks DEQ for this opportunity to engage with the agency on opportunities to further improve the CPP. We hope our comments will assist DEQ in ensuring significant, sustainable emissions reductions that are real, cost-effective, and equitable.

If you have any questions or would like to discuss our comments further, please reach out to me at kwilliams@nwnatural.com.

Respectfully,

Kathryn Williams
VP, Public Affairs & Sustainability

Appendix A

Examples Illustrating CCI Carbon Accounting Gaps

This appendix highlights the importance of ensuring rigorous carbon accounting is applied to the implementation of the Community Climate Investment ("CCI") program. Absent the application of such measures, the program could lead to double-counting of emission reductions or to emissions leakage—outcomes that would undermine the overall success of the Climate Protection Program ("CPP"). NW Natural appreciates the Department of Environmental Quality's ("DEQ") consideration of these illustrative examples and would welcome the opportunity to participate in technical workshops hosted by DEQ on this topic.

The possibility for double-counting exists when combining the provisions of the Draft Rule that state that when a covered party purchases one CCI, it receives one emissions credit that can be used to net against its emissions for compliance,[1] and that one of the goals of the CCI program is to "accelerate the transition from residential, commercial, industrial and transportation-related uses of fossil fuels to lower carbon sources of energy."[2] If this means that CCI funds can be used for switching from energy sources covered in the program to energy sources not covered in the program, double-counting of emissions reductions could occur, absent robust greenhouse gas ("GHG") accounting measures.

DEQ has several options for protecting against double-counting in the final CPP, including allowing covered parties to direct the distribution of their CCI funds and, thus, choose the source of their CCI credits. Avoiding double-counting is a major component of the offset provisions in other jurisdictions that allow entities to comply with mechanisms (like CCIs) that are not (typically) direct emissions reductions from the covered parties. DEQ should adopt similar safeguards here.

Table 1: Example Where CCI Funds are Used for Fuel-Switching from Covered Parties

In the example in Table 1, a covered party purchases CCIs as a means to comply with their emissions cap designated by the CPP program:

Row		Period 1	Period 2
1	Emissions cap/allowances	10	8
2	CCI credits Purchased	2	0
3	CCI credits used for compliance		2
4	Emissions reduction from fuel-switching funded by CCIs		2
5	Actual emissions of covered party	10	8
6	Reported emissions of covered party (net CCI credits)	10	6
7	Societal emissions from covered party	10	8

Here the covered party has an emissions cap (compliance obligation) as detailed in the CPP of 10 units of emissions in the first compliance period (period 1) and 8 units of emissions in the second compliance period (period 2).

[1] *See* OAR 340-271-0020(6) and OAR 340-271-0820(3a)(A).

[2] *See* OAR 340-271-0900(4).

Without additional action not accounted for in the CCP program, the covered party would have emissions of 10 in both periods 1 and 2. To comply with the emissions cap of 8 in period 2, the covered party purchases two CCI credits in period 1 (row 2) to use the CCI credits for compliance in period 2 (row 3). In this example, the CCI funds are used for fuel-switching energy usage from the covered party (e.g., a natural gas utility) to a non-covered energy use (e.g., electricity), which results in reduced energy supplied from the covered party and a reduction in the direct emissions associated with the energy supplied by the covered party by 2 units of emissions (row 4) to 8 in period 2 (row 5). It is important to note that the covered party also received the two CCI credits for the funds it provided to an approved CCI entity in period 1. To show the double-counting issue, assume the covered party uses the 2 CCI credits it has in period 2 to net against its actual emission of 8 units and reports 6 units of emissions in period 2 in its compliance reporting. In this example, the CCI funds were used for direct emissions reduction from the covered party in the form of fuel-switching, but the covered party also could receive CCI credits that it can use to meet its compliance obligation. This means that the CCI program generated 2 units of actual emissions reduction, though 4 units can be claimed due to the double-counting system set up when combining the provisions in OAR 0200, 0820, and 0900.

Furthermore, if funds from the CCI program are allowed to be used for fuel-switching energy services to parties not covered by the program, the emissions associated with the non-covered party taking on this additional societal energy need must be included in the emissions reduction evaluation submitted by the CCI entity and reviewed by DEQ. Consider again the example shown in Table 1. If the fuel-switching paid for by the CCI funds results in the non-covered party that took on the new energy needs having increased emissions to serve the increased needs (e.g., electric sector emissions increase), the CCI program could be double-counting emissions reductions *and* causing emissions leakage, which would not achieve the goal of reducing emissions in Oregon (or more appropriately, globally) (see Table 3).

Table 2: Example Where CCI Funds are Used for Emission Reduction Outside Covered Emissions (i.e., Used for Offsets):

Table 2 shows the same example as above, but requires that CCI funds be true offsets[3] to show that GHG accounting integrity is maintained:

Row		Period 1	Period 2
1	Emissions cap/allowances	10	**8**
2	CCI credits Purchased	**2**	0
3	CCI credits used for compliance		**2**
4	Emissions reduction from fuel-switching funded by CCIs		**0**
5	Actual emissions of covered party	10	10
6	Reported emissions of covered party (net CCI credits)	10	**8**
7	Societal emissions from covered party	10	**8**

[3] The definition for "offset" is an emission reduction that takes place separate from and outside the emissions directly covered by the program.

Table 3: Example Where CCI Funds are Used for Fuel-Switching from Covered Parties with Emissions Leakage to Non-Covered Parties in the State

Table 3 illustrates what may be the most likely outcome of the draft CPP rules as they relate to natural gas utilities and the potential use of CCI funds for electrification of direct-use gas utility space heating loads.

Row		Period 1	Period 2
1	Emissions cap/allowances	10	8
2	CCI credits Purchased	2	0
3	CCI credits used for compliance		2
4	Emissions reduction from fuel-switching funded by CCIs		2
5	Actual emissions of covered party	10	8
6	Reported emissions of covered party (net CCI credits) (row 1 - row 4)	10	6
7	Emissions added to non-covered party from fuel-switching leakage		2
8	Actual societal emissions for serving same energy needs (row 5 + row 8)	10	10
9	Societal emissions reported by the state for the same energy needs (row 6 + row 7)	10	8

While many presume that electrification of direct-use heating loads reduces emissions, that is not the case in many situations. On average in the state, emissions for heating with a natural gas furnace are comparable to the emissions from heating with a high-efficiency electric heat pump, and for about one third of natural gas customers, electrifying their heating with an electric heat pump would appreciably raise emissions from that heating need in Oregon in the near term.

Furthermore, the majority of electric heating in the state remains from inefficient resistance heating (e.g., electric furnaces or baseboard heating) rather than the more efficient usage from heat pump technology. Table 4, below, provides the annual emissions associated with average single-family residential space heating in Oregon with the current emissions intensities of the state's largest utilities:[4]

Table 4: Current Emissions (Metric Tons CO2 per Year) for Residential Space Heating by Equipment Type and Utility

	Electric Heat Pump	Resistance Electric	Gas Furnace	Gas Heat Pump
PGE	2.4	4.1		
PacifiCorp	3.8	6.5		
NW Natural			2.7	1.9

[4] Emissions intensities are from the most recent year of available data from DEQ's GHG inventory. Energy usage estimates from equipment types are from a study completed by the Energy Trust of Oregon as part of PUC Docket No. UM 1565.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Reply Testimony of Mary O. Moerlins

OREGON LOW INCOME ENERGY EFFICIENCY PROGRAM
EXHIBIT 2200

June 6, 2021

EXHIBIT 2200 – REPLY TESTIMONY – OREGON LOW INCOME ENERGY EFFICIENCY PROGRAM

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Mary O. Moerlins. I am the Director Environmental Policy and Corporate Responsibility at NW Natural. I have worked for the Company since 2013. My responsibilities include managing customer and company environmental programs and environmental policy priorities, delivering company philanthropic investments and partnerships and managing the team that delivers support to our low-income communities and customers.

Q. Please describe your education and employment background.

A. I received my bachelor's degree in Biological Sciences from Agnes Scott College and my master's in public administration from Georgia State University. Prior to joining NW Natural in the fall of 2013, I worked in two environmentally focused nonprofits in Atlanta, Georgia—First Fernbank Museum of Natural History from May of 2005 through November of 2009, where I developed and implemented environmental and science education, and Piedmont Park Conservancy, where I held the role of Director of Education and Sustainability from 2009-2013. During my tenure at NW Natural, I have held a series of roles that are all focused on components of the Company's corporate responsibility functions including sustainability, environmental policy and philanthropic investment.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. The purpose of my Reply Testimony is to respond to the Opening Testimony of Charity Fain on behalf of the Coalition of Communities of Color, Sierra Club, Verde, Climate Solutions, Oregon Environmental Council, Columbia Riverkeeper, and Community Energy Project (collectively, the "Coalition") regarding its proposed modifications to NW Natural's Oregon Low Income Energy Efficiency ("OLIEE") program.

Q. Please summarize your testimony.

A. First, I describe the Company's OLIEE program, which provides energy efficiency and weatherization measures to low-income customers. Next, I respond to the Opening Testimony of Coalition witness Charity Fain proposing certain modifications to the OLIEE program. In response to her testimony recommending the elimination of the use of OLIEE funds to pay for natural gas furnaces, I explain that there is no legislative or regulatory policy support for this proposal, and that it should be rejected. In response to her proposal to increase the incidental home repair allowance amount of $1,000, I explain that the Coalition has not justified increasing this amount, but that the Company is open to re-evaluating the $1,000 limit after learning more about the needs of its customers by completing an information gathering effort via a survey of households that have received weatherization services and engaging with OLIEE stakeholders. In response to the Coalition's proposal to add language to the OLIEE tariff, Schedule 320, to promote investments in attic and wall insulation, even when the investments do not achieve a 1.0 cost efficiency ratio, I explain that I do not believe that change is necessary or appropriate given the various funding options for measures that do not meet the cost-effectiveness target. Finally, I respond to the Coalition's concerns regarding the level of spending for OLIEE relative to the available balance and explain the challenges the Company experienced as a result of the COVID-19 pandemic and explain how the Company plans to enhance its efforts to reach more customers in the coming years.

II. OREGON LOW INCOME ENERGY EFFICIENCY PROGRAM

Q. What is the OLIEE program?

A. The OLIEE program is funded through a designated portion of the Public Purposes Funding Surcharge (see Schedule 320). OLIEE funds are used to finance weatherization projects, high-efficient gas equipment and energy literacy services for NW Natural gas customers who qualify as low income, defined as less than 200 percent of the federal poverty line. The weatherization work is done in partnership with Community Action Agencies and approved service providers. OLIEE funds are delivered through two programs: (1) Community Action Plan (“CAP”) and the (2) Open Solicitation Program (“OSP”). The OSP amplifies funding opportunities for certain types of dwellings, tenant profiles, investments and projects that fall outside of CAP parameters. The primary goal of the OSP is to provide cost-effective, energy efficiency assistance to a greater number of low-income households in NW Natural’s Oregon service territory through a broad and diverse network of delivery channels. As shown in Table 1, below, over the past nine years, 2,189 homes have been weatherized through OLIEE, amounting to an estimated annual 547,539 therms saved.

Table 1. OLIEE Program Summary

	Homes weatherized (Target)	Homes weatherized (Actual)	Reimbursed Measure Costs	Reimbursed Health, Safety and Repairs	Estimated therms saved
2012-2013	213 to 328	151	$442,326	$63,257	36,995
2013-2014	253 to 358	201	$664,069	$80,537	46,756
2014-2015	208 to 334	198	$791,611	$85,928	45,876
2015-2016	238 to 351	231	$1,246,030	$193,184	52,817
2016-2017	300	260	$1,521,200	$237,019	59,232
2017-2018	320	299	$1,935,009	$289,364	103,708
2018-2019	300	260	$1,567,192	$242,617	73,441
2019-2020	306	248	$1,595,651	$185,938	68,320
2020-2021	545	341	$1,561,476	$156,805	60,394
Totals		2,189	$11,324,564	$1,534,649	547,539

Q. Did NW Natural propose any modifications to the OLIEE in this proceeding?

A. No, the Company has not proposed any OLIEE program modifications as part of this proceeding.

Q. Did any party to this proceeding provide testimony regarding the OLIEE?

A. Yes. The Coalition provides testimony proposing changes to OLIEE to: (1) eliminate the use of OLIEE funds to pay for natural gas furnaces; (2) increase the incidental home repair allowance amount of $1,000; and (3) add language to Schedule 320 to promote investments in attic and wall insulation, even when the investments do not achieve a 1.0 cost efficiency ratio.[1] Additionally, the Coalition questions the level of spending for OLIEE relative to the available balance.[2] I will respond to these issues in turn.

[1] Coalition/300, Fain/27-30.

[2] Coalition/300, Fain/27-30.

A. Use of OLIEE Funds for Natural Gas Furnaces

Q. What is the Coalition's rationale for its proposal to eliminate the use of OLIEE funds to pay for natural gas furnaces?

A. The Coalition is advocating for fuel-switching and transitioning the Company's natural gas customers off the Company's system. Specifically, the Coalition argues that installing new high-efficiency natural gas furnaces for low-income customers will delay their eventual transition away from natural gas service, and further, assuming that continued investment in the natural gas system will result in stranded assets, that low-income customers will disproportionately bear the costs of escalating rates as natural gas service bills increase.[3] The Coalition also questions whether installation of high-efficiency natural gas furnaces is cost-effective, alleging that the Company's own documents reflect that "gas furnaces often are not cost effective."[4]

Q. What is your recommendation regarding the Coalition's proposal that OLIEE funds should no longer be used for the installation of natural gas furnaces?

A. NW Natural disagrees with the Coalition's proposal and asks the Commission to reject it. The source of the Public Purposes Funding Surcharge funding is the Company's natural gas customers, and it follows that the funds should be used to provide support for natural gas service. While the Coalition is advocating for fuel-switching—meaning the electrification of homes that are currently using natural gas for space heating—there is no legislative or regulatory policy direction

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[3] Coalition/300, Fain/23.

[4] Coalition/300, Fain/28.

supporting fuel-switching from natural gas to electric appliances, nor is there any policy direction suggesting that natural gas furnaces should stop being installed.

Q. How do you respond to the Coalition's arguments about the future of the natural gas utility business?

A. While the Coalition has characterized the transition of NW Natural's customers away from the natural gas system as inevitable, as discussed in greater detail in the Reply Testimony of Kimberly Heiting and Ryan Bracken (NW Natural/1700, Heiting-Bracken), the Company believes there is an important role for the natural gas system—and for RNG, hydrogen, and synthetic gas—in meeting Oregon's emissions reductions targets in the coming years. The Commission should decline the Coalition's request to make a significant policy change that would presuppose a diminished role for natural gas utilities in Oregon's energy future. Moreover, the Coalition's proposal does not deliver benefits to the NW Natural customer base from whom the funds are collected.

Q. The Coalition also questions whether the installation of natural gas furnaces may be cost-effective.[5] What are the cost-effectiveness requirements in Schedule 320?

A. Schedule 320 provides that, subject to two exceptions, the energy efficiency measures that qualify for OLIEE funding must be cost-effective by meeting the Savings to Investment ("SIR") ratio of 1.0 or better. The evaluation of the SIR ratio for energy efficiency measures is performed through the use of the Energy

[5] Coalition/300, Fain/23.

Analyzer Software and is applied on a whole house basis, rather than on a measure-specific basis.

Q. How do you respond to the Coalition's comment that the installation of natural gas furnaces may not be cost effective?

A. The characterization that all natural gas furnace replacements are not subject to a cost-effectiveness test is incorrect. Schedule 320 includes an exception to the cost-effectiveness test for the installation of new high-efficiency natural gas furnaces to replace non-functioning heating equipment. The Coalition incorrectly asserts that this exception was created in 2019.[6] In fact, the change that removed the cost-effectiveness requirement for non-functioning natural gas furnaces was made back in 2013.[7] It is important to understand that the cost-effectiveness test was removed for equipment that was "red-tagged" or non-functional, and which could not pass a cost-effectiveness test due to its non-operational condition.[8] In other words, the revision in 2013 to eliminate the cost-effectiveness threshold for natural gas furnaces simply meant that OLIEE funding could be used to replace a furnace that was no longer functional.[9]

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[6] Coalition/300, Fain/23.

[7] NW Natural OPUC Advice No. 13-23, Staff's Public Meeting Memo for Item CA14 at 2 (Nov. 18, 2013) (supporting NW Natural's request to "treat 'no heat' furnaces as qualifying measures outside of the cost-effectiveness test").

[8] NW Natural OPUC Advice No. 13-23, First Revision of Sheet 320-4 (Oct. 18, 2013).

[9] As stated in the cover letter to Advice No. 13-23 stating the need for the change: "Agencies are required to model non-functioning furnaces within [the analyzer tool] to demonstrate that replacing the furnace will result in cost effective therm savings. The problem is that a non-functioning furnace has no therms to be saved and when modeled in this way, may not pass a cost-effectiveness test."

Q. Why was it important to except red-tagged equipment from the cost-effectiveness test?

A. If the customer has red-tagged or non-functional heating equipment, it means that they may not have a safe source for heating during the winter months. The Company believes that it is critically important that OLIEE funds can be used to replace non-functioning equipment with a high-efficiency gas furnace to ensure that the customer has access to a safe and efficient source for heating.

B. Health, Safety, and Repair Limit of $1,000

Q. What is the Coalition's rationale for increasing the OLIEE funding for incidental repairs beyond the limit of $1,000?

A. The Coalition asserts, without any analysis and without proposing any alternate amount, that the $1,000 limit is exceedingly low, and that "often, critical upgrades are necessary before weatherization investments can be effective."[10]

Q. To clarify, is the weatherization limit per household set at $1,000?

A. No. The $1,000 limit applies only to the subset of health, safety and repair ("HSR") measures. HSR measures are those items that, if not completed, would adversely impact the safety and health of the occupants or the effectiveness of the energy efficiency measures.

Q. What are some examples of HSR measures?

A. HSR measures include upgrades to enable weatherization equipment or energy efficiency equipment to function properly, or that are important to health and safety,

[10] Coalition/300, Fain/22.

and can include piping relocation, repairs to walls and/or windows, mold abatement, lead paint abatement, and ventilation fans for equipment and spaces such as bathroom fans.

Q. What is the total OLIEE funding amount available per household?

A. The total OLIEE funding amount available per household is $17,600, which includes $10,000 for weatherization measures, $5,000 for heating equipment (if needed), $1,000 (on average per household) for HSR measures, and $1,600 for Community Action Partner ("Agency") administrative costs.

Q. Is the $1,000 amount on HSR measures a strict cap per household?

A. No. As detailed in Schedule 320, the maximum annual HSR disbursement available to each Agency is $1,000 times the actual number of households treated by the Agency in the Program Year (collectively, the "HSR Allowance"). Each Agency has discretion in the use of their individual HSR Allowance and may use more or less than $1,000 on any one home. Each Agency must manage its HSR funds to ensure that the average HSR amount per home is not more than $1,000. Thus, if certain homes do not require any HSR measures, the homes that do require any HSR measures may qualify for additional amounts, in the discretion of the Agency.

Q. Has the HSR limit always been set at $1,000?

A. No, until 2016, the HSR limit was set at $440. In 2015 and 2016, however, NW Natural, the OLIEE Advisory Council ("OAC") and the CAP agencies determined that the funding was not adequate to address certain ventilation requirements that were included in more recent building standards.[11] Based on these conversations with key stakeholders and a demonstrated need for additional funding, the Company requested an increase to the HSR measure funding under the OLIEE program, and the Commission ultimately approved the Company's request.

Q. What is your recommendation regarding the $1,000 limit on HSR measures?

A. The Company is open to re-evaluating the current level of funding for HSR measures, but believes it is premature to do so in this case as the Coalition has not supported its proposal to increase the limit—or provided a specific proposal to which to respond. That said, in early 2022, the Company began the development of an information gathering effort to survey households that had received weatherization services. The results of this survey will provide new information, experiences and feedback from weatherization recipients that can help to gain insights, inform practices and improve processes. The survey results may also provide guidance as to whether there is a need to increase the HSR measure funding. Additionally, to the extent an increase may be needed, the Company would plan to work with its key stakeholders for the OLIEE program, the CAP agencies and the OAC[12] to determine the appropriate amount. In sum, NW Natural

[11] NW Natural OPUC Advice No. 16-01: https://edocs.puc.state.or.us/efdocs/UAA/uaa123344.pdf

[12] As defined in Schedule 320, the OLIEE Advisory Committee (OAC) will assist in advising the Company on OLIEE program implementation, and evaluation. The OAC will be comprised of at least one member each from the Company, the Commission staff, the Community Action Partnership of Oregon (CAPO), plus two or more representatives from the CAP, and when appropriate, one or more representatives from the OSP. The OAC was last convened in June 2021 with representation from CAPO, NW Energy, PUC, CUB and the following CAPs (Community Action Agency Washington County, Clackamas County CAP, Community Services Consortium, Homes for Good, Multnomah County Community Services, Mid-Willamette Valley Community Action Agency and Yamhill County CAP). The next OAC meeting is scheduled for June 23, 2022.

does not believe any changes are warranted at this time, but is open to revisiting this issue following the survey results discussed above and engaging the OLIEE program stakeholders.

C. Promoting Attic and Wall Insulation

Q. What is the Coalition's rationale for its proposal to add language to Schedule 320 to promote investments in attic and wall insulation, even when the investments do not achieve a 1.0 cost efficiency ratio?

A. The Coalition references a report by the Energy Trust of Oregon, the Commission, and the Oregon Housing and Community Services that studied how to reduce the energy burdens of low-income Oregonians. In that report and with regard to natural gas utility customers, it concluded that "wall insulation and smart thermostats are the best weatherization and energy efficiency upgrades that would most significantly reduce energy consumption in low-income dwellings."[13]

Q. What is a 1.0 cost efficiency ratio and why is it important?

A. As discussed above, the cost efficiency ratio (or Saving to Investment Ratio or SIR) of 1.0 is a metric that is used to evaluate whether energy efficiency measures are cost effective. The Energy Analyzer Software evaluates the measures that are available and determines what measures will meet the metric on a whole-home basis. Through application of the 1.0 SIR, the measures that provide the most "bang for the buck" will be prioritized. Public Purpose Funding Surcharge dollars are first directed to the measures that will yield the greatest savings in therms—

[13] Coalition/300, Fain/29.

which also results in the greatest monthly bill savings for the customer. The use of Energy Analyzer Software informs Community Action agencies of the most impactful measures, however the agency staff are not constrained on a project-by-project basis and may determine measures for a dwelling that may not be the most efficient but have non-energy benefit for the resident.

Additionally, Schedule 320 aligns with state and federal weatherization cost-effectiveness requirements and is consistent with how weatherization / energy efficiency funding from other federal sources operate. OLIEE funding is combined with Low Income Home Energy Assistance Program ("LIHEAP") and Oregon Housing and Community Services ("OHCS") so that houses may be holistically weatherized.

Q. How are weatherization measures evaluated for cost-effectiveness?

A. The CAP agencies use energy modeling software to evaluate the available measures, however, the results generated from the software inform, but do not unilaterally drive, decisions on energy efficiency measures. The weatherization crews use home energy audits and diagnostic equipment, including blower door tests and infrared cameras (which identify heat loss) to determine the most cost-effective measures for a particular home.

Q. What types of measures are typically evaluated?

A. Typical measures include installing insulation, reducing air infiltration and pressure imbalances, sealing and repairing ducts, and tuning and repairing heating and cooling units. That said, according to conversations with CAP weatherization staff, the specific measures that are ultimately performed are client-informed and determined on a case-by-case situation at the discretion of the CAP agency based on several factors including an assessment of the dwelling, available dollars from OLIEE and from other sources, and an assessment of what may be required to get the dwelling ready for specific measures as well as the energy modeling audit.

Q. Is it your understanding that there is significant demand for wall and attic insulation that is not being met due to the application of the cost-effectiveness ratio?

A. No. To the contrary, it is my understanding that attic and wall insulation is occurring on many of the projects we provide rebates for even when those particular measures are not determined to be cost-effective for purposes of qualifying for OLIEE funding.

Q. Does that mean that the CAP agencies are not applying the SIR?

A. No. While the SIR provides guidance and direction on each project, the cost effectiveness ratio target is set to apply program-wide. In each heating year the target cost effectiveness is an average across all implemented projects. Our CAP agency partners hold some degree of discretion in identifying the right solutions for clients. Additionally, if OLIEE funding is not applicable or is exhausted for a given dwelling, there may be additional complementary sources of funding available to the CAP agency to accomplish the desired measures in a client's home, such as LIHEAP (as detailed above). Complementary electric utility energy efficiency funding, state and federal dollars and even private funds may also be leveraged by CAP agencies to serve their clients.

Q. Does the OSP also provide for supplemental funding for measures that may not be cost-effective?

A. Yes, non-cost effective measures that deliver energy conservation benefits to low income NW Natural customers can also be funded with OSP dollars. The OSP is "open" by design, and the guiding principle of OSP is to increase the number of eligible customers who receive weatherization services. It is a supplemental, complementary resource within OLIEE designed to help unlock, expedite and streamline the delivery of weatherization funding and projects.

Q. How do you respond to the Coalition's proposal to add language to Schedule 320 to promote investments in attic and wall insulation, even when the investments do not achieve a 1.0 cost efficiency ratio?

A. I do not think that change is needed at this time. Through the existing framework, investments in attic and wall insulation may be eligible for OLIEE funding and additional resources may be available through the OSP or through complementary funding sources, such as LIHEAP.

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D. OLIEE Funding Balance

Q. The Coalition also comments that NW Natural has not been using all of the OLIEE funds that are available, noting that in the 2019-2020 program year, NW Natural disbursed $2.3 million of an available $4 million, and, in the 2020-2021 program year, the Company disbursed $2.2 million of an available of $4.8 million.[14] How do respond?

A. NW Natural has not been disbursing all available amounts in recent years. The use of OLIEE funds is directly tied to performing energy efficiency and weatherization measures in customers' homes, and as a result of the COVID-19 pandemic, there were limitations on the ability of NW Natural's community partners to access customer homes. Additionally, both NW Natural and its community partners had staffing issues that limited their abilities to use all available funds.

Q. What is the current balance of available OLIEE funds?

A. The current balance is approximately $8.5 million.

Q. How did the balance accumulate?

A. The outstanding OLIEE account balance is the result of a confluence of factors, including the approval of increased resources earmarked for OLIEE activities occurring immediately before the onset of the COVID-19 pandemic and diminished project volumes and staffing capacities resulting from the pandemic.

- ***Increased funds:*** In response to guidance from partner CAP agencies, NW Natural proposed and was granted a higher level of funding per-

[14] Coalition/300, Fain/27-28.

customer dwelling. This increase in funding collection was approved and occurred shortly before the beginning of the COVID-19 pandemic.

- ***COVID-19***: Due to restrictions and limitations associated with in-home services and staffing at CAP agencies and other partners, the increased funding was not able to be distributed via projects at the speed initially intended or planned. Further, increased demands for services and support as a result of COVID-19 resulted in fewer resources available for weatherization projects. While there were fewer whole home retrofits completed in response to 2020 restrictions, CAP agencies reported an increase in the number of equipment-only projects they were able to perform.

In reflection of the high priority that the Company puts on serving low-income customers and facilitating the accelerated expenditure of collected low income weatherization funds, multiple positions have been either built or restructured to serve this population of customers, including the hiring or a Community Partnerships and Programs Manager and the active recruitment of a Low Income Weatherization Program Manager to replace the program lead for low income weatherization who left NW Natural in March 2022.

Q. Does NW Natural have a plan to spend down the surplus OLIEE funds?

A. Yes. The Company plans to reactivate the OSP, complete a staffing reorganization, perform enhanced outreached to enhance community awareness of OLIEE funding, and implement additional strategies unlock the funding. I will describe each element of the Company's plans in turn.

Q. Please describe the Company's plans to reactivate the OSP.

A. In 2021, NW Natural embarked on a year-long process to restore delivery of the OSP. While NW Natural had previously funded OSP projects (2016-2018), the program was temporarily shuttered for multiple heating years in an effort to refine reporting and process document practices and enable higher transparency. Renewed attention to the OSP spurred new conversations and created the opportunity to: reimagine the program and its potential for impact; optimize activities and offerings; increase take-up; tap unspent funds; and establish a clear process for awarding, delivering and evaluating program funds moving forward. The program has, as of 2021, been reopened and is currently disseminating funds to qualifying projects. This funding will be reflected in the 2021-2022 and 2022-2023 heating years.

Q. Please describe the Company's staffing reorganization.

A. In 2021, the Community Partnerships and Program Manager position was hired with the intention of increasing engagement with community partners and to restore the OSP. Work over the year resulted in the creation of a large project that is currently in process and will be funded in 2022. The multi-partner initiative will provide full energy retrofits for six buildings that house, shelter and care for approximately 320 low-income children, youths and adults with intellectual and developmental disabilities each year. Upgrades are projected to save approximately 3,300 therms and 200,000 kWh annually and reduce utility costs by over $25,000.

Additionally, the team is on track to onboard an energy efficiency program manager by summer 2022—the backfill position will focus solely on low-income weatherization projects, allowing for increased staff capacity dedicated to this work than how the role was previously defined.

Q. Please describe the Company's enhanced outreach.

A. Through consultation with CAP agency partners and other community-serving nonprofit organizations, NW Natural has discovered that program awareness is the greatest barrier to participation in the program. The NW Natural team is partnering with community-serving nonprofit organizations to create opportunities for eligible household to participate in the low-income weatherization program. Some examples of this increased engagement include the use of billboards, bill insert promotional materials in multiple languages and provision of program information via trusted community partners.

In 2021, NW Natural designed and implemented a robust outreach campaign on new resources available for customers with past-due bills. The outreach plan was informed by community partners and prioritized hardest to reach populations; and the strategies piloted through this effort will continue to enhance outreach efforts going forward, providing a foundation for similar outreach for initiatives and programs like OLIEE.

Q. What other strategies has the Company identified to help unlock funding?

A. NW Natural is undertaking the following measures:

- Information on weatherization was recently added to the home assessment checklist performed by several nonprofits in the Portland-metro area that serve senior residents. Residents are then connected directly with the local CAP agency for more information.

- Several CAP agencies and other nonprofit partners report struggling to find a weatherization contractor—a challenge that continues to slow projects. To that end, we are in active conversations with several workforce development partners to increase weatherization training opportunities and grow the workforce.
- Landlord engagement is another barrier to successful weatherization. In response, we are partnering with a nonprofit organization to convene local landlords of affordable and low-income, multi-unit housing to share information on the benefits of energy efficiency retrofits and the resources available to them.

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Reply Testimony of
Kyle T. Walker and Robert J. Wyman

LEXINGTON RNG PROJECT COST OF SERVICE AND RATE SPREAD, COVID-19 DEFERRAL AMORTIZATION AND RATE SPREAD, AND DECOUPLING AND WEATHER ADJUSTED RATE MECHANISM (WARM) PROPOSALS
EXHIBIT 2300

June 6, 2022

EXHIBIT 2300 - REPLY TESTIMONY – LEXINGTON RNG PROJECT COST OF SERVICE AND RATE SPREAD, COVID-19 DEFERRAL AMORTIZATION AND RATE SPREAD, AND DECOUPLING AND WEATHER ADJUSTED RATE MECHANISM (WARM) PROPOSALS

Table of Contents

I. INTRODUCTION, SUMMARY AND STIPULATION

Q. Are you the same Kyle Walker and Robert Wyman who filed Direct Testimony in this proceeding on behalf of Northwest Natural Gas Company ("NW Natural" or the "Company")?

A. Yes, we presented NW Natural/1300, Walker and NW Natural/1400, Wyman.

Q. What is the purpose of your Reply Testimony in this proceeding?

A. We highlight revenue requirement components of the stipulation filed by the joint stipulating parties, present the updated cost of service model and rate spread for the Lexington Renewable Natural Gas Project ("Lexington RNG Project"), and discuss the amortization of the parties' proposed rate spreads for the deferral of costs associated with the COVID-19 pandemic ("COVID-19 Deferral"). Last, we address Staff's proposals on the Company's Decoupling and Weather Adjusted Rate Mechanism ("WARM") rate mechanisms.

Q. Does the stipulation reached by parties narrow the issues from your Direct Testimonies?

A. Yes. NW Natural, Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), the Alliance of Western Energy Consumers ("AWEC"), and the Small Business Utility Advocates ("SBUA") (collectively, the "Stipulating Parties") reached a settlement on revenue requirement, rate design and certain other issues (the "Stipulation"), which was filed with the Commission on May 31, 2022.

Q. What items were included in the Stipulation?

A. As discussed in the Reply Testimony of Zachary Kravitz (NW Natural/1600, Kravitz), the Stipulating Parties agreed to the following items in the Stipulation: Revenue requirement, cost of capital, rate spread and design, attestation for capital projects, depreciation rates, Horizon 1 depreciation rates, TSA Security Directive 2 deferral, Williams Pipeline Outage, billing determinants for Schedules 183 and 197, update to Tariff Rule 11, cost study analysis of Tariff Rate Schedule 3 Non-Residential (Commercial), workshop relating to the difference in fixed costs for residential multi-family vs. single family dwellings, and tariffs.

Q. What issues from NW Natural/1300, Walker were not included in the Stipulation, and therefore, addressed in this Reply Testimony?

A. The only issue remaining from NW Natural/1300, Walker is the Lexington RNG Project cost of service.

Q. What issues from NW Natural/1400, Wyman were not included in the Stipulation, and therefore, addressed in this Reply Testimony?

A. The only issue remaining from NW Natural/1400, Wyman is the rate spread for the Lexington RNG Project.

Q. Are there any other issues not raised in your Opening Testimonies that you will be addressing in this Reply Testimony?

A. Yes. Staff raised two new issues in its Opening Testimony that we will be addressing here. First, Staff witnesses Dlouhy, Fox, and Storm propose to amortize the 2020 and 2021 balance of the Company's COVID-19 Deferral over two years subject to certain adjustments and an earnings test set at 50 basis points under the Company's authorized return on equity.[1] Additionally, Staff has proposed a rate spread to allocate costs to all customers classes.[2] Second, Staff witness Scala has proposed to modify the Company's Decoupling mechanism to bifurcate the mechanism between new and existing customers, which in turn, also requires a change to the Company's WARM mechanism.[3]

II. LEXINGTON RNG COST OF SERVICE AND RATE SPREAD

Q. Has the Company updated its cost-of-service analysis for the proposed Lexington RNG Project?

A. Yes. As described in the Reply Testimony of Anna Chittum, NW Natural/2100, Chittum, inputs to the cost-of-service model have changed since the Company filed its Direct Testimony. Therefore, the Company updated the cost-of-service model and associated output in confidential Exhibit NW Natural/2301, Walker-Wyman.

Q. Has the revenue requirement for the Lexington RNG Project changed since the initial filing?

A. Yes. With the update of inputs, including, but not limited to, capital, operating and maintenance expense and the price of "brown gas," the overall revenue requirement has declined.

1 Staff/1500, Dlouhy-Fox-Storm.

2 *Id.*

3 Staff/1300, Scala.

Q. Please summarize CUB/200, Gehrke in regards to rate spread and the Lexington RNG Project.

A. CUB supports the Company's initial rate spread proposal to spread costs on an equal cent per therm basis to all sales and transportation customers, with one modification.[4] CUB proposes that the cost allocation apply to special contract customers as well. CUB's proposal allocates the cost of the Lexington RNG Project to all customers except storage.[5]

Q. Does the Company propose to recover the cost of the Lexington RNG Project from different customers than proposed in its initial filing?

A. Yes. Due to the final rules in Oregon's Climate Protection Program ("CPP") being released, the Company believes all customers, including those with special contracts, should bear the cost of the Lexington RNG Project, consistent with CUB's position. The Company agrees with CUB that the CPP rules make NW Natural the single point of regulation for all emissions associated with customers taking natural gas service on its distribution system.[6] Therefore all customers should pay to decarbonize the product moving through the Company's distribution system.[7]

[4] NW Natural/1300, Walker/28, lines 16-17, and NW Natural/1404, Wyman/1.

[5] CUB/200 Gehrke/46, lines 16-22 and /47 lines 1-2.

[6] CUB/200 Gehrke/42, line 21 and /43 lines 1-3.

[7] CUB/200 Gehrke/46, lines 5-15.

Q. AWEC argues that none of the costs of the Lexington RNG Project should be allocated to transportation customers.[8] Do you think transportation customers should be allocated some of the Lexington RNG Project costs?

A. Yes. Under the CPP, NW Natural is responsible for its transportation customers' emissions and NW Natural, not transportation customers, must pay penalties if transportation customers emit more greenhouse gases (GHG) than permitted. Therefore, NW Natural cannot, as AWEC contends, rely on transportation customers' own energy efficiency programs and NW Natural does not currently offer energy efficiency programs to its transportation customers. Because the CPP places all the compliance risk on NW Natural, not transportation customers, transportation customers are not incentivized to reduce emissions to the levels contemplated in the CPP. In other words, because the CPP does not pose any compliance risk for transportation customers, it is unclear why they would, in AWEC's words, pursue "self-directed energy efficiency programs"[9] to reduce emissions beyond the status quo. Therefore, allocating a portion of the Lexington RNG Project costs to transportation customers is appropriate.

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[8] AWEC/100, Mullins/33, lines 16-17.

[9] AWEC/100, Mullins/33, lines 8-9.

Q. AWEC argues that "it is too early to tell the most cost-effective way for individual customer classes to comply with the CPP"[10] and, therefore, allocating CPP costs to transportation customers should be delayed. Is this a persuasive argument?

A. No. This argument could apply to any action that NW Natural seeks to take to comply with the CPP and would also presumably apply if NW Natural were to attempt to direct the costs, as AWEC suggests, of energy efficiency programs to transportation customers. In short, because the CPP is in its early stages and went into effect only two weeks after it was adopted,[11] AWEC's argument would be equally valid if made by any customer class regarding any CPP cost. Yet the CPP is currently in effect and NW Natural must incur costs to comply with it. The Company does not have the opportunity to take a wait-and-see attitude towards compliance and cannot rely on programs that have not been developed yet, such as additional energy efficiency programs for transportation customers. Instead it must pursue compliance now and the Lexington RNG Project is an integral part of that compliance.

[10] AWEC/100, Mullins/32, lines 15-16.

[11] The CPP was adopted on December 16, 2021, and went into effect on January 1, 2022. While the CPP did go through an extensive rulemaking process, several material changes were made compared to the draft rules, including accelerated emissions reductions.

Q. Notwithstanding AWEC's argument, do you have any analysis demonstrating that acquiring RNG is a cost-effective way of complying with the CPP?

A. Yes. Based on the draft CPP rules that were available in September 2021, NW Natural modeled a comprehensive compliance strategy to meet the compliance requirements of the CPP, which includes renewable fuels and several other compliance mechanisms. The base case modeling shows NW Natural acquiring increasing amounts of RNG, eventually exceeding ORS 757.396 sales portfolio targets (e.g., 30 percent of sales portfolio by 2050) in 2031 through 2050. Because NW Natural's September 2021 modeling was based on the draft CPP rules, not the rules that ultimately were adopted in mid-December 2021 and went into effect on January 1, 2022, it does not reflect that the final rules now mandate accelerated emissions reductions. In its modeling work, NW Natural examined a more aggressive emissions path in its "Accelerated Timeline" Scenario, which requires more RNG than the base case, and this modeling is currently being updated in NW Natural's IRP.

Q. Does AWEC acknowledge that NW Natural performed modeling in the CPP showing increased RNG acquisitions?

A. Yes. AWEC states that it has "significant concerns with whether RNG is the most cost-effective compliance alternative for large customers . . ."[12] but does not express the nature of those concerns. AWEC suggests that there may be other

[12] AWEC/100, Mullins/33, lines 6-7.

less expensive ways to comply with the CPP, but, again, it would, at the very least, take time to develop such programs and NW Natural must comply with the CPP right now.

Q. AWEC argues that the transportation customers should not pay for the Lexington RNG Project because its purpose was to meet ORS 757.396 sales targets, not to comply with the CPP.[13] Should transportation customers not be allocated any Lexington RNG Project costs because its original purpose was to meet ORS 757.396 targets?

A. No. Regardless of its original purpose, the Lexington RNG Project benefits transportation customers because it can also be used for CPP compliance (see above). Because transportation customers benefit from the Lexington RNG Project, they should be expected to pay a share of the cost.

Q. AWEC argues that the costs of the Lexington RNG Project should be spread on an equal percent of margin basis, rather than an equal cents per therm basis.[14] Do you agree with AWEC?

A. No. For NW Natural to comply with CPP, it must reduce the number of therms of natural gas its customers use. Such reductions could be accomplished through energy efficiency or displacing natural gas with RNG, as provided in the CPP (see above). Because CPP compliance is based on therms of natural gas used, it makes sense to allocate cost in the same way (i.e., equal cents per therm).

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[13] AWEC/100, Mullins/32, lines 7-9.

[14] AWEC/100, Mullins/32, lines 7-21.

Q. Why does the Company believe all customers should pay?

A. The final CPP rules define the Company as the "point of regulation", which makes the natural gas utility responsible for all of its customers' emissions.

Q. How do you respond to AWEC's statement that "NW Natural's proposal is contradictory in that it assigns a larger portion of the costs of RNG to transportation customers, while otherwise ignoring cost causation in the context of the base rates increase?"[15]

A. In this rate case, as well as in its last rate case (UG 388), the Company has strived to promote rate spread proposals that equitably distribute the incremental revenue requirement such that the rate classes as a whole are moved closer to parity based on their indicated cost causation as determined in the Long-Run Incremental Cost ("LRIC") study filed with each case. These proposals have represented an incremental approach, in that they work to move all rate classes closer to parity, but do so in a manner that works to minimize rate shock. With the CPP compliance costs, cost causation is tied not to the direct and indirect costs of provisioning safe and efficient service for our customers, but rather it is tied directly to emissions associated with natural gas consumption. As such, it is reasonable to spread the CPP costs based on the number of therms used. The Company understands that this cost allocation methodology will result in economic impacts for Oregon businesses, and if the Commission believes it is appropriate to open a further

[15] AWEC/100. Mullins/31, lines 18-20.

investigation or policy docket into the allocation of CPP compliance costs, the Company would support further examining this issue.

Q. With respect to CUB's proposal to allocated costs to NW Natural's special contracts customers, could including special contracts in cost recovery cause timing issues?

A. Yes. Due to the limited time available to update or amend the special contracts, the rate effective date for cost recovery is likely to occur before the contracts can be updated.

Q. What do you suggest if the special contracts cannot be updated or amended by the rate effective date?

A. The Company will file a deferral application in order to defer the special contracts cost of the Lexington RNG Project. We will then seek to amortize the deferral to special contract customers at a later time, after the contracts themselves have been updated.

Q. Does AWEC express a concern regarding tax benefits of the Lexington RNG Project investment?

A. Yes. AWEC's concern is that the tax benefits from the Lexington RNG Project investment, specifically deferred income taxes which influence the cost of this investment to ratepayers, will be restricted or limited due to the ownership structure. AWEC indicated this concern is supported by NW Natural's own workpapers and a response to a data request. AWEC stated, "Based on NW Natural's workpapers, however, the amount of ADIT [accumulated deferred income tax] that will accrue to ratepayers will be limited in future years, as tax benefits are allocated to BioCross. This was also discussed in response to AWEC Data Request 30”[16] (see Exhibit AWEC/103, Mullins/3).

Q. Is AWEC correct that NW Natural indicated lower or restricted deferred tax liabilities?

A. No. The Company stated that the deferred tax liability, included in determining the cost of the Lexington RNG Project investment for customers, was *slightly higher* relative to what the deferred tax liability would be only looking at book and tax depreciation differences for the underlying Lexington RNG Project plant.

Q. What recommendation did AWEC make to address its concern?

A. AWEC recommended that, “the Commission require NW Natural to impute any amount of ADIT which has been limited as a result of the portion of the Lexington facility owned by BioCross.”[17]

Q. Do you agree with AWEC’s recommendation that the Commission require NW Natural to impute a deferred tax liability?

A. No. AWEC’s concern is not supported by the items AWEC referenced, NW Natural’s workpapers or NW Natural’s response to AWEC Data Request 30 (see confidential Exhibit NW Natural/2302, Walker-Wyman). Also, deferred tax liabilities are included in determining rate base in the cost of service because they represent an actual temporary cash savings in the utility operation that should benefit customers. Imputing deferred tax liabilities that do not exist is providing a

[16] AWEC/100, Mullins/37.

[17] AWEC/100, Mullins/37-38.

benefit to customers for cash savings that did not occur. Finally, normalization is required for Oregon utility rate making and is codified in ORS 757.269(2)(e), "…the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates… contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law." Imputing deferred taxes that do not exist, to the extent they relate to plant, may be considered a violation of the normalization requirement.

IV. COVID-19 DEFERRAL AMORTIZATION AND RATE SPREAD

Q. Please briefly describe the COVID-19 Deferral.

A. Commission Order No. 20-401 in docket UM 2114, authorized the Company and other signatory utilities to defer costs associated with the COVID-19 pandemic for later ratemaking per the conditions in the adopted Stipulated Agreement on the Effects of the COVID-19 Pandemic on Energy Utility Customers. The Company filed an application for deferral accounting for COVID-19 related costs for the 12-month period ended March 23, 2021, docketed as UM 2068, which was approved by the Commission in Order No. 20-380. The Company subsequently filed a supplemental application for deferral reauthorization for the 12-month period ending March 23, 2022, approved in Order No. 22-093.

Q. Did the Company propose to begin amortization of its COVID-19 Deferral in its Direct Testimony?

A. No, the Company did not propose an amortization of this deferral in its Direct Testimony of this docket.

Q. Has Staff proposed that the Company begin amortization of its COVID-19 Deferral?

A. Yes, in Opening Testimony, Staff proposed that the Company amortize its 2020 and 2021 COVID-19 Deferral balances as of December 31, 2021, over a period of two years as a temporary increment in the Company's next Purchased Gas Adjustment ("PGA") effective November 1, 2022.[18]

Q. What is the Company's response to Staff's proposal and timeline for amortization of the COVID-19 Deferral?

A. First, we note that the Reply Testimony of Amanda Faulk, NW Natural/2000, addresses Staff's proposed adjustments to the 2020 and 2021 balances of the COVID-19 Deferral. Our testimony addresses Staff's proposed earnings test set at 50 basis points under the Company's authorized return on equity, and rate spread associated with the amortization of the deferral. With respect to Staff's two-year amortization proposal beginning November 1, 2022, the Company is not opposed to the proposal.

Q. What is the Company's COVID-19 Deferral balance to be amortized?

A. The Company's COVID-19 Deferral balance as of December 31, 2021, per its 2021 4th Quarter COVID-19 Deferred Accounting Report filed in Docket RG 90, is $10.7 million.[19]

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[18] Staff/1500 Dlouhy-Fox-Storm/16, lines 18-22.

[19] *NW Natural's 4Q 2021 Report of COVID-19-Related Costs and Benefits*, Docket No. RG 90, Supplemental Application filed January 28, 2022. See also: Staff/1500 Dlouhy-Fox-Storm/8 Table 15-1.

Q. Does Staff propose that amortization of the COVID-19 Deferral be subject to an earnings test?

A. Yes. Staff proposes an earnings test for the direct costs associated with COVID-19. The proposed earnings test is "[a]uthorized ROE (9.40 percent) less 50 basis points or 8.90 percent."[20] Staff states that the "the earnings test, coupled with deferral and amortization, is designed to ensure that utilities do not receive the extraordinary relief of retroactive rate making for added costs when earnings exceed a reasonable rate of return."[21] Staff also states that "a reasonable rate of return for purposes of the earnings review depends on the nature of the deferral."

Q. Do you believe that an earnings test set at 50 basis points below the Company's authorized ROE provides a reasonable rate of return?

A. No. Although Staff's Direct Testimony states that the Company's reported 2020 ROE is 8.56 percent, which would allow for full recovery of at least the first year of the COVID-19 deferral, the Company does not believe that it is appropriate to conclude that an amount less than the Company's authorized ROE is "reasonable" for purposes of an earnings test for the COVID-19 Deferral. Rather, the Company's authorized ROE, by definition, represents a reasonable rate of return and should be used to determine whether the direct costs of COVID-19 can be amortized.

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[20] Staff/1500, Dlouhy-Fox-Storm/17.

[21] Staff/1500, Dlouhy-Fox-Storm/17, lines 10-13 (citing *In re Portland General Electric Co. Docket No. UE 82, Order No. 93-257* (Feb. 22, 1993).

Using the Company's authorized ROE also avoids attempting to reduce the Company's ROE by an arbitrary amount (50 basis points, in this instance). Staff does not explain why it chose the severely punitive level to set the earnings test beyond stating that "many people and business suffered negative economic consequences of the pandemic," implying that NW Natural should suffer economic consequences too. In contrast, the Company's authorized ROE is supported by considerable analysis during a general rate proceeding and represents a reasonable rate of return.

The very low threshold for the earnings test is also unexpected given the backdrop of the Oregon utilities response to the pandemic -- immediately and proactively providing unprecedented relief to customers when the pandemic began and throughout the pandemic. Additionally, the costs that we incurred were directly related to the ability to continue providing safe and reliable service to our customers, including safety gear and supplies and COVID-19 testing, among other costs.

Q. In their Opening Testimonies, did parties propose rate spread treatments for the Company's COVID-19 Deferral?

A. Yes. CUB and Staff each proposed a COVID-19 Deferral rate spread in their Opening Testimonies. CUB proposed that the deferral be spread to all customers on an equal cents per therm basis.[22] Staff's proposal groups the COVID-19 Deferral costs into three groups and recommends a different rate spread approach

[22] CUB/200 Gehrke/37, lines 13-15.

for each group based on an analysis of cost causation, and for one category, the flow of direct and indirect economic benefits to each customer class.[23] AWEC did not propose rate spread treatment for the COVID-19 Deferral specifically, but did argue that while supplemental schedules can be allocated on a basis consistent with each schedule's cost causation, LRIC study results and overall rate impacts should be considered.[24]

Q. Please describe Staff's rate spread proposal in more detail.

A. As noted above, Staff's proposal groups the COVID-19 Deferral costs into three groups, and recommends a different rate spread for each. The groups, and their associated costs as enumerated in the UM 2114 Order No. 20-234 *Attachment A: Oregon Non-Binding Term Sheet - Energy Utilities*,[25] as well as their proposed rate spread are as follow:

- Group 1: Term Sheet Category A. Direct COVID-19 related costs, offset by direct savings and benefits. Includes the costs related to setting up work from home arrangements, offset by reduced spending on business-related expenses such as travel and meals and entertainment. Spread to this group on an equal percent of Test Year margin revenue basis to all customer classes.

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[23] Staff/1500 Dlouhy-Fox-Storm/43 lines 5-19 and /44, lines 1-11.

[24] AWEC/100 Mullins/53, lines 5-9.

[25] *In the Matter of Public Utility Commission of Oregon, Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*, Docket UM 2114, Order No. 20-234, Appendix A, pages 19-22 (October 2, 2020).

- Group 2: Term Sheet Category C. The cost of bad debt expense over the baseline authorized in the Company's last rate case. Spread to this group on a Base Year total revenue basis to all customer classes.
- Group 3: Term Sheet Categories B, and D through F. These categories include late payment fees not assessed, costs associated with the COVID-19 Bill Payment Assistance Program, and reconnection charges and field visit fees. Spread to this group based on Staff's direct and indirect economic multiplier methodology as described in Staff/1500, Dlouhy, Fox, and Storm.

Q. Please summarize the effect of Staff's COVID-19 Deferral rate spread proposal.

A. Group 1 represents roughly 23.1 percent of the Company's non-adjusted COVID-19 Deferral balance. Groups 2 and 3 represent 18.4 percent and 58.5 percent, respectively. Staff's proposal spreads the deferral amount at an amount above an equal percent of post-Stipulation revenue requirement margin revenue basis for the residential rate class (roughly 1.047 times the overall revenue increase from the deferral on a margin basis),[26] and less than an equal percent of post-Stipulation

[26] The COVID-19 Deferral is proposed as a temporary rate adjustment, which has an effect on total revenues, not margin. The effect is expressed in terms of margin here as the impacts can be better compared across all the rate classes because transportation schedules do not include commodity revenues.

margin revenue basis for the commercial and industrial rate classes (roughly 0.882 and 0.989 times, respectively).[27]

Q. What is the Company's position on the COVID-19 Deferral amortization and rate spread?

A. The Company is not opposed to amortizing the full balance of its COVID-19 Deferral as of December 31, 2021 over two years in its next PGA, effective November 1, 2022. The Company is supportive of a rate spread that responds to the principle of cost causation as it relates to the categories of costs found in the deferral.

Q. Please describe how the Company believes the principle of cost causation applies to each of Staff's three COVID-19 Deferral cost groups.

A. Each of the three COVID-19 Deferral cost groups proposed by Staff and described above contain COVID-19 related cost items and benefits (both direct and indirect) that impact each of the rate classes unevenly. Therefore, the principle of cost causation would suggest that the deferral amortization should be spread in a manner that recognizes the characteristics of the individual cost elements:

- Group 1: Direct COVID-19 related costs such as the cost of transitioning some employees to a work from home setup while outfitting essential field workers with personal protective gear, as well as the direct savings from prohibiting employee travel, are items that benefited all NW Natural

[27] Note that this analysis assumes that the rate class categories in Tables 15-8, 15-9, and 15-10 of Staff/1500 Dlouhy-Fox-Storm/42-43 are meant to follow the same order as Table 15-8 (namely, from top to bottom: RES, COM, IND).

customers. These elements represent operational adjustments necessary for the continued safe and efficient provision of utility service for all of the Company's customers during the pandemic.

- Group 2: The cost of bad debt expense over baseline cost element is delineated by rate class in each of the Company's Docket RG 90 COVID-19 Deferred Accounting Reports. Staff recommends against using these rate class based values for the rate spread allocation for Group 2. Instead, Staff recommends a rate spread for all rate classes, but implies a willingness to adjust this recommendation depending on further discovery around the Company's methods for establishing the baseline.[28] Based on the bad debt balances the Company has tracked and reported in its COVID-19 Deferred Accounting Reports, it would be reasonable for any rate spread for this group to follow the classes in which the bad debt expense was tracked and incurred.
- Group 3: Staff characterizes the bill credit and bill offset cost elements in this group as akin to "short-term transfer payments from a government agency to consumers."[29] Such transfers, Staff argues, lead to a fiscal multiplier effect and in turn all customer classes (and Oregon's economy as a whole) benefitted to some extent, at least indirectly, as recipients spent the money that they otherwise would have applied to their NW Natural

[28] Staff/1500, Dlouhy-Fox-Storm/40, lines 9-17 and /41 lines 1-2.

[29] Staff/1500, Dlouhy-Fox-Storm/24, lines 10-16.

accounts elsewhere. The Company notes that the cost elements in question (late payment fees not assessed, and the COVID-19 Bill Payment Assistance Program) directly benefited the residential rate class more than any other customer class. These bill offsets, which Staff conceptually equates to transfer payments, were in fact dollars used to reduce NW Natural account balances, not cash payments directly provided to customers. While sympathetic to the concept of the fiscal multiplier effect, we note that Staff's cost causation analysis is more indirect in nature, and does not consider the fact that some portion of the bill credit stimulus undoubtedly leaked outside of the Company's commercial and industrial customer base (e.g., the money customers would have otherwise used to pay their NW Natural account balances was instead used on necessities such as other utility bills or gasoline, or spent at establishments that are not NW Natural customers). For these reasons, we feel that Staff's methodology may overstate the amount of Group 3 costs caused by and the benefits flowing to the commercial and industrial rate classes.

Q. What is the Company's response to CUB's rate spread proposal?

A. The Company does not believe that CUB's proposal to spread deferral amortization costs to all customers on an equal cent per therm basis aligns with cost causation principles. For instance, many of the Group 1 costs (direct COVID-19 savings and benefits) should be allocated on a revenue basis, not a consumption basis because these costs do not vary based on system throughput. Further, Group 3 costs are related to programs specifically targeted to customers in the residential class; we do not feel that an equal allocation of these costs on a consumption basis across all customer classes appropriately matches these costs to the rate class that most benefitted from these programs.

Q. What is the Company's position on the COVID-19 Deferral rate spread?

A. As explained above, the Company recognizes that rate class cost causation varies across the three cost element groups defined by Staff. Each rate class is impacted by the COVID-19 related cost items and benefits in at least one of the cost element groups. Therefore, the Company is supportive of spreading a portion of the deferral amortization across every rate class based on principles of cost causation. We do not, however, propose a specific rate allocation here. The Company would like to review AWEC's and SBUA's responses to Staff's proposal, especially as it pertains to Group 3 cost elements, before committing to a COVID-19 Deferral amortization rate spread.

V. DECOUPLING AND WARM PROPOSALS

A. Staff's Decoupling and WARM Proposals

Q. Please summarize Staff's Decoupling proposal.

A. Staff states that new customers use less gas than established, or existing, customers on a weather normalized average use-per-customer ("UPC") basis. Based on this conclusion, Staff proposes to bifurcate the residential Decoupling calculation between established customers and new customers that join the system after each rate case.[30]

[30] Staff/1300, Scala/24-28.

Q. Did the Company have any discussions with Staff after they filed their Opening Testimony?

A. Yes. After discussions with Staff, we understand that it is proposing that the Company reevaluate the UPCs for both new and existing customer groups as part of each rate case filing and move the formerly new customer group into the established customer tranche for the purposes of calculating the Decoupling customer baselines.

Q. Please describe the information that Staff relied on to determine new customers have lower UPCs.

A. Staff relied on the Company's response to Staff Data Request ("DR") 454 (see Exhibit NW Natural/2303, Walker-Wyman), which requested NW Natural to provide the average annual and monthly usage for: (1) an established residential customer location; and (2) a new residential customer location. In response to the DR, the Company conducted a preliminary analysis that estimated a weather normalized UPC of 651.4 therms annually for an established residential location and 494.1 therms annually for new residential locations. The Company defined a new residential location as a residential premise that had a natural gas service installed and initiated within the past ten years (beginning 2012 through 2021). The Company derived these amounts using the same methods as the Test Year normalized use-per-customer forecast as described in NW Natural/1400, Wyman/Pages 5-15 of this docket.

Q. Did the Company's analysis define a new customer as one whose account was created in the past ten years?

A. No, it did not. The Company defined a new residential location based on the service initiation date. Service initiation is the point at which natural gas service is first installed and a meter is set at the premise, not the point when a new customer account is opened. Because accounts are opened and closed when customers move to or away from a premise, which can occur many times throughout the service life of a single premise, it would not be appropriate to define a new residential customer location based on account age for purposes of this analysis. Therefore, the Company's analysis did not contemplate customer account age.

Q. What was Staff's response to the Company's analysis parameters?

A. Staff witness Michelle Scala indicates that "[f]rom Staff's perspective, a ten-year bracket for new installations may not quite capture what Staff envisioned as 'new,' however it may be that Staff needs to better understand the Company's rationale for using these parameters."[31]

Q. What is the Company's rationale for using the ten-year parameter to define new residential services?

A. Staff did not provide the Company with the characteristics it envisions make up the profile of a new residential customer location. In response to Staff DR 500 (see Exhibit NW Natural/2304, Walker-Wyman), the Company explained that it chose to include services initiated in the past ten years because the UPC model requires

[31] Staff/1300, Scala/20, lines 12-15.

data from multiple winter heating seasons to adequately interpret how the load demand for a customer class (or a subset thereof) responds to observed heating degree days. If the Company does not use a large enough sample in its analysis, it will not have enough data points to produce model coefficients that are statistically significant. There are also other practical reasons for not limiting the evaluation of new services installed to the very recent past. The initialization of service may not coincide with the installation of all appliances, and there may be a gap between when the premise is completed, is placed on the market and sold, and when a new household fully moves in. Due to these reasons, there could be multiple billing periods between when a service is initialized and when it begins to produce data adequate for establishing a normalized annual use.

Finally, we emphasize that the ten-year historical period includes services installed and initiated from the end of 2021 *up to* ten years in age. This translates into a weighted average service age of the evaluated residential premises of roughly five and a half years. Of all the new services evaluated, roughly one-tenth have an age of ten years, roughly one-tenth have an age of nine years, and so on.

Q. Please summarize any changes that Staff seeks to make to Company's Weather Adjusted Rate Mechanism (WARM).

A. Staff proposes that no changes to WARM be made at this time.[32]

[32] Staff/1300, Scala/33.

B. Issues with Staff's Proposals

Q. What are the Company's positions on Staff's proposals?

A. The Company believes that revising the Decoupling mechanism may be warranted at some point in the future. However, such a revision would require significant changes to the Company's customer information system ("CIS") and, because that system is outdated and will soon be replaced, we do not think it is the right time to make those changes. In addition, to make the changes proposed by Staff, the WARM program would have to be changed because it uses the same heating coefficient as the Decoupling mechanism. Therefore, if the Decoupling mechanism includes a separate coefficient for new customers, the WARM program would need to apply that coefficient to new customers as well.

Q. Please further explain why NW Natural is concerned about making changes to its CIS at this time.

A. As explained in the Direct Testimony of Jim Downing (NW Natural/600, Downing), NW Natural's CIS is "the integrated framework that manages essential customer-facing functions, including billing and customer field services."[33] Significant changes to CIS would have to be made to implement Staff's proposal. However, NW Natural's existing CIS is 23 years old.[34] Making such significant changes to an outdated system that will soon be replaced as part of the Company's Horizon 2 project is an inefficient use of Information Technology & Services resources, which

[33] NW Natural/600, Downing/11.

[34] *Id.*

are already stretched thin to implement the low-income discount program, Horizon 1, and TSA Security Directive 2.

Q. What changes to CIS would have to be made to implement Staff's proposal?

A. Changing the Decoupling mechanism would require changing the CIS code in order to flag new customers past a certain date. The CIS coding changes would be needed to generate reports for the Decoupling calculations (existing and new customers), create an additional billing rate for new customers and provide financial reporting based on the outcomes of the two Decoupling calculations. CIS would also need to update the WARM mechanism to incorporate two different heating coefficients for the two types of customers (existing and new). This would essentially create two separate WARM programs within CIS with different inputs for the WARM adjustment calculations.

Q. Why would the heating coefficients for WARM need to be updated?

A. The change to the Decoupling mechanism is precipitated by a difference in usage characteristics between the existing customer base as compared to new customers. The UPC is the metric that provides the distinction, and the UPCs are determined by different usage coefficients that are derived from statistical analyses. If normal UPCs are lower for new customers, it follows that their heating response to differences in weather, as measured by heating degree days, is likely lower. To use the overall heating coefficient from an analysis of existing customers would likely overstate the amount of usage that would result from variances in weather (warmer or colder) for new customers. A new heating coefficient would be needed to produce a decoupling baseline for new customers. The same coefficient should also be used in the WARM mechanism that applies to new customers.

Further, the purpose of the usage coefficient under the decoupling mechanism is identical to the purpose of the same coefficient under the WARM mechanism, which is to use the coefficient with measures of weather variance to weather normalize the customer's usage. Using different coefficients under the two mechanisms would create a mismatch of customer usage between the two mechanisms, causing inappropriate financial impacts.

Q. Are there any other issues with implementing Staff's proposal at this time?

A. Yes. In addition to making significant changes to NW Natural's soon to be retired CIS and updating the heating coefficients for WARM, NW Natural would also have to work out many other issues associated with such a change. While we appreciate Staff's analysis and recommendation relating to Decoupling, these types of systematic changes are difficult to accomplish in an ongoing rate case, especially without knowing that the issue is going to be raised. The Decoupling and WARM mechanisms impact several workstreams at the Company, including Accounting, Information Technology & Services (including CIS), Rates & Regulatory, Budget and Finance, among others. In sum, any change to the Decoupling mechanism must be thoroughly evaluated and carefully planned

C. NW Natural's Proposals

Q. Does the Company propose to change the Decoupling and WARM mechanisms in this rate case?

A. Not at this time. The Company believes the parties should continue to work through the Decoupling and WARM issues, and we look forward to further testimony in this docket.

Q. You mention above that a change to the Decoupling mechanism may be warranted at some time, so why not propose a change now?

A. As stated above, making any change to the Decoupling mechanism at this time is problematic due to the Company's outdated CIS that will soon be replaced, how such changes interact with WARM, and current resources that are already implementing several new programs (low income discount program, Horizon, and the TSA Security Directive 2). Lastly, the Company believes that all parties to this docket, including the Company itself, need to fully evaluate the current and potential new mechanisms, so that the effects of any changes to the Decoupling mechanism are completely understood prior to implementation.

Q. Will the Company commit to a timeline to analyzing changes to its Decoupling mechanism?

A. Yes. The Company commits to analyzing and making a Decoupling and WARM proposal in the Company's first general rate case following the CIS implementation (i.e., Horizon 2).

Q. Does this conclude your Reply Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibits of Kyle T. Walker and Robert J. Wyman

LEXINGTON RNG PROJECT COST OF SERVICE AND RATE SPREAD, COVID-19 DEFERAL AMORTIZATON AND RATE SPREAD, AND DECOUPLING AND WEATHER ADJUSTED RATE MECHANISM (WARM) PROPOSALS EXHIBITS 2301-2304

June 6, 2022

EXHIBITS 2301-2304 – LEXINGTON RNG PROJECT COST OF SERVICE AND RATE SPREAD, COVID-19 DEFERRAL AMORTIZATION AND RATE SPREAD, AND DECOUPLING AND WEATHER ADJUSTED RATE MECHANISM (WARM) PROPOSALS

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EXHIBIT 2301

REDACTED

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June 6, 2022

BEFORE THE

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EXHIBIT 2303

June 6, 2022

NW Natural

Rates & Regulatory Affairs

UG 435

Request for a General Rate Revision

Data Request Response

Request No.: UG 435 OPUC DR 454

454. Please provide the average annual and monthly usage for: (1) an established residential customer location and (2) a new residential customer location.

Response:

Please refer to UG 435 OPUC DR 454 Attachment 1. The usage amounts presented in Attachment 1 are weather normalized and were derived using the same methods as the Test Year normalized use-per-customer forecast as described in Docket No. UG 435 NW Natural/1400, Wyman/Page 5-15.

NW Natural
Rates & Regulatory Affairs
Oregon Jurisdictional Rate Case - UG 435
Test Year Ending October 31, 2023
Current Average Weather Normalized Annual and Monthly Usage, by the Residential Location Types: New and Established
UG 435 OPUC DR 454

	Month	(Therms) UPC Load New Location	(Therms) UPC Load Established Location
1	Jan	81.20	106.96
2	Feb	70.44	89.77
3	Mar	61.23	78.94
4	Apr	42.15	55.36
5	May	23.76	32.60
6	Jun	14.51	20.75
7	Jul	10.36	15.38
8	Aug	9.24	13.59
9	Sep	11.06	15.77
10	Oct	30.02	39.98
11	Nov	58.46	75.91
12	Dec	81.64	106.35
Current Annual UPC:		**494.06**	**651.37**

**Note 1: "UPC" is use-per-customer.*
**Note 2: New location is defined for the purposes of this analysis as a new service put into place in the last ten years (beginning 2012 through 2021).*
**Note 3: Established location for the purposes of this analysis is any service established prior to 2012.*

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 435 / UG 411

NW Natural

Exhibit of Kyle T. Walker and Robert J. Wyman

LEXINGTON RNG PROJECT COST OF SERVICE AND RATE SPREAD, COVID-19 DEFERAL AMORTIZATON AND RATE SPREAD, AND DECOUPLING AND WEATHER ADJUSTED RATE MECHANISM (WARM) PROPOSALS
EXHIBIT 2304

June 6, 2022

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 500

500. Please identify the Use-Per-Customer (UPC) of a typical new connection/residential customer for the Test Year and explain how the Company arrived at this value.

Response:

Please refer to the Company's response to UG 435 OPUC DR 454 for the estimated weather normalized annual UPC associated with a new residential customer in the Test Year.

The Company queried billing cycle data for Oregon residential premises that had service initiated within the last ten years (beginning 2012 through 2021). The usage amounts presented in OPUC DR 454 were weather normalized and were derived using the same methods as the Test Year normalized use-per-customer forecast as described in Docket No. UG 435 NW Natural/1400, Wyman/Page 5-15.

The Company chose to include services initiated in the past ten years because the model requires data from multiple winter heating seasons to adequately interpret the load response a customer class (or a subset thereof) has to observed heating degree days. If the Company did not use a large enough sample, we will not have enough data points to produce model coefficients that are statistically significant. There are other practical reasons for not limiting the evaluation of new services installed to the very recent past: The initialization of service may not coincide with the installation of all appliances, and there may be a gap between when the premise is completed, is placed on the market and sold, and when a new household fully moves in; due to these reasons, there could be multiple billing periods between when a service is initialized and when it begins to produce data adequate for establishing a normalized annual use.

Finally, we note that the use of the ten-year historical period translates into a weighted average service age of the evaluated residential premises of roughly five and a half years. Of all the new services evaluated, roughly one-tenth have an age of ten years, roughly one-tenth have an age of nine years (etc.), … and roughly one-tenth have an age of just one year or less.