Before the

PUBLIC UTILITIES COMMISSION
STATE OF NEW HAMPSHIRE

DG 22-045

Direct Testimony of
Faisal Deen Arif and Mark Thompson

June 8, 2023

000001

Contents

000002

000003

INTRODUCTION

Q1: Please state your name, occupation, and business address.

A1: My name is Faisal Deen Arif. I am employed by the New Hampshire Department of Energy as the Director of Gas in its Regulatory Division. My business address is 21 South Fruit Street, Suite 10, Concord, New Hampshire, 03301.

Q2: Please summarize your educational and professional experience.

A2: I am an economist by training. I have a Ph.D. in Economics with specialization in Regulatory Economics and International Trade and Finance. I also have over 7 years of relevant professional experience in the field. For additional information, please see Attachment 1 (CV – Deen Arif)

Q3: Please state your name, occupation, and business address.

A3: My name is Mark Thompson. I am president of Forefront Economics Inc, 3800 SW Cedar Hills Blvd, Suite 241, Beaverton, Oregon, 97005. I am currently a sub-contractor working for the New Hampshire Department of Energy on the H. Gil Peach and Associates, LLC team.

000004

Q4: Please summarize your educational and professional experience.

A4: I am an economist by training specializing in the field of econometric modeling and energy utility economics. I have a Master of Science degree in Agricultural and Natural Resource Economics with a minor in statistics from Oregon State University and a Bachelor of Science degree in Agricultural Economics from Oklahoma State University. Since founding Forefront Economics in 1993 I have led and conducted a wide range of empirically based projects in the area of energy utility policy, load forecasting, program impact evaluation and revenue decoupling evaluation. Prior to starting Forefront Economics, I managed DSM program evaluation within the Rates and Regulatory affairs department of Portland General Electric. For additional information, please see Attachment 2 (CV – Mark E. Thompson).

Q5: What is the purpose of your testimony in this proceeding?

A5: Our testimony will:

- provide observations and recommendations on Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty (Liberty, Liberty Gas or the Company) claim of $3,511,438 (hereafter referred to as $3.5 million) in decoupling revenue from Decoupling Year 4 (DY4) in this current Docket No. DG 22-045; and
- highlight other issues relevant to the claim.

SUMMARY

Q6: Please state the issues you intend to explore in your testimony.

A6: In our testimony, we plan to provide the following:

- A discussion on Liberty Gas's current claim to recover $3,511,438 from DY4;
- An analysis of the impacts of:
  - Equivalent Bills (EB) calculation
  - Rate schedule re-classification
  - Other issues; and
- DOE recommendation.

Q7: What is Liberty's claim and what is the basis of its claim?

A7: Liberty Gas proposes to recover $3,511,438 in decoupling revenues that includes:

- $727,670[1] from prior year under-collection[2] from DY3 (spanning from September 1, 2020 to August 31, 2021)
- $2,783,768[3] from under-collection in DY4 (running from September 1, 2021 through August 31, 2022)

[1] $307,157 from residential and $420,513 from Commercial & Industrial (C&I) customers. See page 2, Table 1a of the Technical Statement of Craig A. Holden, Tab 39 in DG 22-045.
[2] In this Technical Statement, Liberty asserts that "[t]he corrected balance carryover of $727,670 for combined residential and commercial solely reflects the estimated uncollected balance of the approved decoupling year 2020/2021 as of August 31, 2022." See page 1, ibid.
[3] $2,551,253 from residential and $232,515 from C&I customers. See page 2, Table 1b, ibid.

000006

- A residential RDAF[4] charge of $0.0423 per therm and a C&I RDAF charge of $0.0055 per therm[5]

Subject to the approval by the New Hampshire Public Utilities Commission (the Commission, or PUC), Section 19, Sub-section D of Tariff 11 provides Liberty the authority to reconcile its decoupling revenues through the RDAF mechanism.

Q8: What is DOE's opinion on Liberty's claim?

A8: Based on the materials reviewed in this case, our most pertinent two observations are summarized as follows:

- **Equivalent Bill (EB) calculation:** is a complex process, performed at the customer-level by Liberty Gas, which is, *de facto*, a proxy for customer count. Given the current decoupling framework that is structured as a Revenue Per Customer (RPC) charge, it is imperative that there be parity in treating actual and trued-up EB counts both for the allowed and actual decoupling revenues. This is not observed in the current case. For a detailed discussion on its impact, please see *Facts and Observations* and *True-ups and Equivalent Bills Calculation* sections of this testimony.
- **Rate Schedule Re-classification:** was performed thrice (in June 2019, June 2020, and July 2021) by the Company[6]. This could impact the allowed revenue targets for rate classes impacted by

[4] RDAF is the Revenue Decoupling Adjustment Factor, a reconciliatory mechanism included in Tariff 11, design to enable the Company to reconcile decoupling revenue accounts.
[5] See page 2, Table 1d of the Technical Statement of Craig A. Holden, Tab 39 in DG 22-045.
[6] See Attachment 3.

000007

reclassification, and specifically impact reported $727,670 prior-period under-collection. See *Rate Schedule Re-classification* section of this testimony for a detailed discussion on this issue.

These two issues are fundamentally linked to Liberty's current $3.5 million claim as they impact the allowed decoupling revenue targets, against which the actual decoupling revenues was compared when Liberty calculated its decoupling revenue shortfall that is presented in this case.

Q9: Please summarize your recommendations on the identified issues.

A9: Due to the significant complexity surrounding the calculations provided by Liberty in support of its decoupling request, the Department of Energy (the Department or DOE) is unable to formulate a specific recommendation on Liberty's current claim; instead, and to assist the Commission, the Department provides summaries of its analysis and observations, which focus on areas where DOE thinks Liberty decoupling mechanism can be made more transparent and reviewable.

ANALYSIS

Facts and Observations

Q10: Please identify the relevant facts related to Liberty's current claim.

A10: Having reviewed the materials from Liberty Gas's multiple submissions as well as the discovery responses, the Department notes the following:

000008

- For Decoupling Year 4 (DY4), Liberty asserts that its overall RDAF under-collection is $3,511,438, of which $727,670 [7] is from prior year under-collection[8] from DY3 (spanning from September 1, 2020 to August 31, 2021), and $2,783,768 [9] is from under-collection in DY4 (covering September 1, 2021 through August 31, 2022).

- The composition of the RDAF under-collection of $2,783,768 from DY4 represents[10]:
  - A revenue deficiency of $1,732,755 (i.e., 62%) due to True-ups (reported four months after any given calendar month)
  - An under-collection of $991,327 (i.e., 36%) due to monthly revenue difference (reported at the end of any given calendar month)
  - A deficiency of $59,686 (i.e., 2%) due to carrying charges (reported at the end of any given calendar month)

- In terms of the disaggregation between the residential and C&I rate classes, the composition of the RDAF under-collection of $2,783,768 from DY4 represents[11]:
  - An under-collection of $2,551,253 (92%) from residential customers
  - A revenue deficiency of $232,515 (8%) from C&I customers

---

[7] $307,157 from residential and $420,513 from Commercial & Industrial (C&I) customers. See page 2, Table 1a of the Technical Statement of Craig A. Holden, Tab 39 in DG 22-045.
[8] In this December 8, 2022 Technical Statement, Liberty asserts that "[t]he corrected balance carryover of $727,670 for combined residential and commercial solely reflects the estimated uncollected balance of the approved decoupling year 2020/2021 as of August 31, 2022." See page 1, ibid.
[9] $2,551,253 from residential and $232,515 from C&I customers. See page 2, Table 1b, ibid.
[10] See Attachment 9 (page 4), which is based on Liberty's Sch4 RDAF – REVISED Page 3 of 3 (from Attachment appended to Technical Statement of Craig A. Holden, Tab 39 in DG 22-045).
[11] See Attachment 9 (page 4).

000009

- For residential customer classes, of $2,551,253 RDAF under-collection:
  - True-up represents $949,817 (37%) of overall residential RDAF deficiency
  - Monthly revenue difference represents $1,531,167 (60%); and
  - Applied interest (carrying charges) represents $70,268 (3%)

- For C&I customer classes, of $232,515 RDAF under-collection:
  - True-up represents $782,938 (i.e., an under-collection)
  - Monthly revenue difference represents ($539,840) (i.e., an <u>over-collection</u>); and
  - Applied interest (carrying charges) represents ($10,583) (i.e., an <u>over-collection</u>)

- The estimated allowed revenue (reported at the end of a given calendar month and before the True-up process) for DY4 is $91,749,158 [12]. [A]

- The actual revenue (reported at the end of a given calendar month and is never trued-up again) for DY4 is $89,082,025 [13]. This actual revenue goes through a monthly adjustment process to arrive at an Adjusted Actual Revenue of $90,757,832, the composition of which is as follows:
  - Actual Revenue: $89,082,025 [B]
  - MEP[14] Premium: ($112,267) [15] [C]

[12] See Attachment 10 (page 2), which is based on Liberty's response to Data Request Set 3 (November 23, 2022) and Technical Session Data Request Set 1 (May 30, 2023).
[13] ibid.
[14] MEP refers to the Managed Expansion Plan program.
[15] A bracketed figure implies a net over-collection and vice versa.

000010

- Low Income Discount[16]: $1,228,786 [D]
- Unbilled daily meter change from prior month[17]: $6,909 [E]
- Unbilled revenue change from prior month[18]: $552,380 [F]
- Adjusted Actual Revenue: $90,757,832 [G] = [B]+[C]+[D]+[E]+[F]

▪ For DY4, the decoupling revenue shortfall based on the monthly adjustments (and prior to the True-up process) is $991,327. [H] = [G] – [A]

▪ For DY4, the reported decoupling revenue shortfall from the True-up process is $1,739,360 [19].

▪ The data does not show a commensurate True-up process for the Adjusted Actual Revenue.

True-ups and Equivalent Bills Calculation

Q11: What are Equivalent Bills and why are they important in determining Liberty's revenue decoupling adjustment factor (RDAF)?

[16] Collected through the Gas Assistance Program (RGAP) component of Local Distribution Adjustment Charge (LDAC). This applies only to R-4 (residential heating) customer class. For a list of Liberty accounts affecting the MEP adjustment, see Attachment 11.
[17] This applies only to a sub-set of C&I customers. For a list of Liberty accounts affecting the adjustment due to unbilled daily meter change for any given calendar month, see Attachment 11.
[18] For a list of Liberty accounts affecting the adjustment due to unbilled revenue change for any given calendar month, see Attachment 11.
[19] This revenue deficiency is attributed to an average 4.4% increase in equivalent bill counts from the True-up process.

A11: Equivalent Bills (EBs) can be thought of as the number of customers normalized to a 30-day[20] month. They are used to establish allowed Revenue Per Customer (RPC) within each rate class by dividing total allowed revenue by equivalent bills at the end of the test year[21]. They are also used to establish monthly allowed revenue during a decoupling year by serving as a multiplier to monthly approved RPC for each rate class.

Q12: Is there an issue with how Equivalent Bills are used in Liberty's decoupling mechanism?

A12: Yes. We see several issues related to EBs that impact the RDAF.

Q13: Please explain these issues.

A13: Equivalent bills are multiplied by approved RPC to determine allowed revenue for each rate class and each month. Liberty uses a four-month period following each month to arrive at a final number of equivalent bills for any given month. For example, equivalent bills for August are not known until December. Liberty produces an initial estimate each month and then a final equivalent bill count four months later. The initial count is comprised of actual equivalent bills for that rate class and calendar month and an estimate of bills to complete the month. A final number for the bills to complete the month is released four months later. This process raises the following issues:

- Allowed revenue for any given month is not determined until four months after that month.
- Actual revenue follows a different process and is known soon after the end of the month.

[20] See section 19 D, sub-section 4d of Tariff 11.
[21] Test Year was 2019. See Docket DG 20-105.

000012

- The difference between the initial and final estimates of bills to complete the month, referred to as the true-ups) almost always work to increase the total equivalent bills and hence the allowed revenue for the month.

Q14: How do actual and allowed revenue follow a different process?

A14: For actual revenue Liberty uses revenue actually recorded as received during any given calendar month. Hence, actual revenue is known within a week following the end of a calendar month. Allowed revenue is calculated as actual equivalent bills multiplied by approved RPC. Liberty waits for four full months following the end of any given month before equivalent bills are considered actual and used for a final estimate of allowed revenue. It is unclear why actual revenue can be known within days following the end of the month but actual number of customers (equivalent bills) cannot be known for four months. The impact on the RDAF of this misalignment between the process for determining actual revenues and actual equivalent bills is unknown.

Q15: Please explain the issue related to true-ups.

A15: True-ups relate to the four-month lag between any given calendar month and when actual equivalent bills are known. Within a week following the end of a calendar month, journal entries for revenue decoupling adjustments for the residential and commercial rate groups are made to align actual and allowed revenues. The initial estimate is based on known equivalent bills for the calendar month and an estimate of the equivalent bills outstanding to complete the calendar month. Four months later another set of journal entries are made to true-up the original estimate of allowed revenue with revised numbers for the actual number of customers (equivalent bills) for that month. For example, revenue

000013

decoupling adjustments for April are adjusted with a true-up based on what happens to April equivalent bills from billing activity in the months of May, June, July, and August.

In a sense the original estimate of equivalent bills to complete any given month is a forecast and the final estimate of equivalent bills to complete a calendar month, available four months later, is the actual. It is reasonable to expect that when comparing actual to forecast the number of times actual is higher than forecast would be roughly equal to the number of times actual is lower than forecast. Likewise, it is reasonable to expect that the difference between actual and forecast tend to offset each other (i.e., average near zero). However, analysis of data provided by Liberty through Data Requests from this current docket DG 22-045 show that actuals exceed forecast equivalent bills in 98% of the cases examined by DOE over a 12-calendar month period September 2021 through August 2022. The average impact from true-ups was to add 2.4% to residential and 4.4% to commercial original estimates of equivalent bills to complete the calendar month.

It is unclear why actual equivalent bills to complete a calendar month are on average 2.4% and 4.4% higher for residential and commercial, respectively, than forecast but the impact on the RDAF is clear. Through the process of true-ups to equivalent bills, Liberty increases (reduces) the revenue to be collected from (returned to) customers through the RDAF component of LDAC.

000014

Q16: What do you recommend?

A16: DOE recommends that Liberty's decoupling mechanism incorporate a similar process for determining actual and allowed revenue that better aligns the two and reduces the complexity associated with the true-up of equivalent bills. One way to achieve this is to move to a decoupling mechanism that is based on total allowed revenue rather than approved revenue per customer. This is an issue that DOE intends to explore further in Liberty's next rate case when the decoupling provision can be changed.

Rate Schedule Re-classification

Q17: Please define rate schedule reclassification.

A17: Rate schedule reclassification is simply the movement of a customer from one rate schedule to a different rate schedule.

Q18: Why is rate reclassification important in the context of decoupling?

A18: The Liberty Revenue Decoupling Mechanism (RDM) is based on Revenue Per Customer. Allowed (target) revenue for any given month is the number of customers in a rate class multiplied by the allowed RPC for that rate class, summed across all rate classes. A change in a customer's rate schedule that results in a change from one rate class to another, will have an impact on total allowed revenue.

000015

Q19: Is the allowed RPC meaningfully different between rate classes.

A19: Yes. There are meaningful differences in allowed RPC between the rate classes tied to differences in the cost to serve various customer classes. As stated, allowed RPC varies monthly and by rate class. The table below shows the allowed annual RPC which is equal to the permanent monthly rates from the DG 20-105 Settlement Agreement (Exhibit 49 from DG 20-105) plus the STEP adjustment for each decoupled rate class summed across all months. Table 1 shows the allowed revenue per customer by rate class when a customer is served by Liberty in that rate class for an entire year.

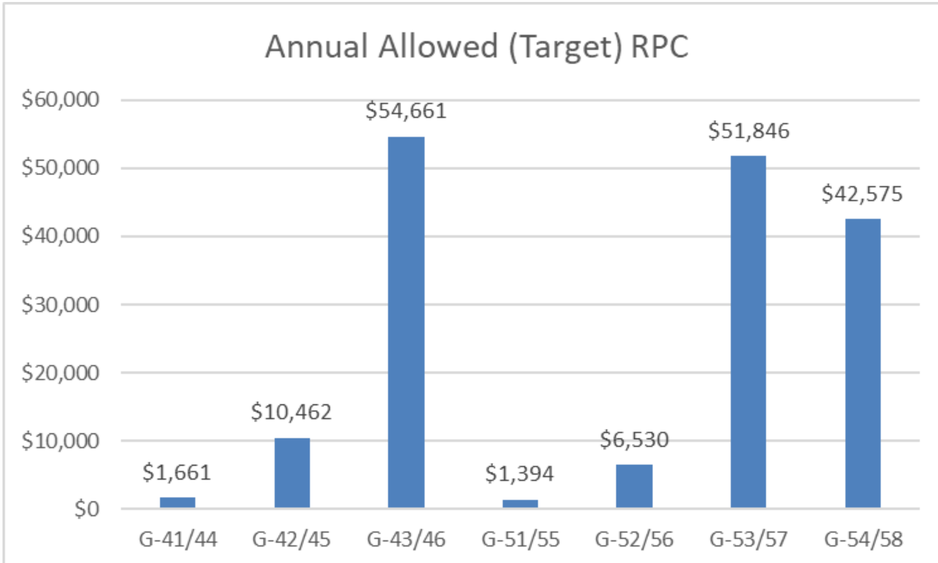
Table 1. Annual Allowed (Target) Revenue Per Customer.[22]

Rate Class	Annual Allowed (Target) RPC
R-1/5	$277
R-3/6	$657
R-4/7	$657
G-41/44	$1,661
G-42/45	$10,462
G-43/46	$54,661
G-51/55	$1,394
G-52/56	$6,530
G-53/57	$51,846
G-54/58	$42,575

As can be seen in Table 1, there are large differences in allowed RPC within the non-residential customer rate classes. Rate classes from the commercial rate group are shown in Figure 1 to better show the large differences in allowed RPC between the commercial rate classes.

[22] Source: Attachment 7 (DG 20-105 Settlement Agreement, Revenue Decoupling Adjustment, Permanent Rates Revenue Per Customer (effective August 1, 2021), Exhibit 49, Bates 036)

000016



Q20: Please provide an example of how rate reclassification impacts allowed revenue.

A20: A customer on, say, rate schedule G-42 that is moved to rate schedule G-43 would increase Liberty's annual allowed revenue by $44,199 ($54,661-$10,462). The Rate Review Process run by Liberty for the period ending May 2021 resulted in the recommendation that 12 commercial customers be moved from G-42 to G-43 (*See* Attachment 3, Liberty's response to DOE Data Requests 3-6 in DG 22-041). If these 12 customers were all present in the test year used for DG 20-105 (12 months ending December 31, 2019) as G-42 customers and then moved to G-43 in a subsequent decoupling year, Liberty's allowed revenue would increase by $530,388 ($44,199 x 12).

Q21: Wouldn't a change in rate schedule also impact actual revenue.

A21: Yes. But because the actual revenue received from the customer would be based on that customer's actual billing determinants and the allowed revenue for that customer is based on the

000017

customer class as a whole, there can be significant differences between the impacts to actual and allowed revenues from rate reclassification. Liberty identified a small change to actual annual revenues, a decline of $22 (0.0%) associated with moving all 12 G-42 customers discussed in the previous answer to the G-43 rate schedule (*See* Attachment 3, Liberty's response to DOE Data Requests 3-6 in DG 22-041). Using this example, moving these 12 customers from G-42 to G-43 would have resulted in an increase in the Commercial Revenue Decoupling Deficiency (or reduction in the Excess) of $530,410 ($530,388 + (-22)) for the decoupling year.

Q22: What has been the net effect of rate reclassification on the Revenue Decoupling Deficiency (Excess) recovered through the RDAF?

A22: We don't know and can't say for sure. The Rate Review Process run by Liberty for the period ending May 2021 resulted in 868 commercial customer rate reclassification recommendations (*See* Attachment 3, Liberty's response to DOE Data Requests 3-6 in DG 22-041). Some changes would allow greater decoupling revenue recovery, some rate schedule changes would reduce Liberty's revenue recovery through the decoupling mechanism, and some of the recommended changes may not have been implemented by Liberty after manual review.

Q23: What do you recommend?

A23: Because rate reclassification after the establishment of a test year will result in imbalances between the test year and decoupling year, we recommend that Liberty not conduct the rate review process between rate cases and test years. This is especially important when using an allowed revenue

000018

per customer based decoupling mechanism rather than a decoupling mechanism based on total allowed revenue. DOE's recommendation is consistent with the recommendation of Liberty's witness Gregg Therrien, Concentric Energy Advisors, in DG 22-041:

> "Recommendation 1: Any C&I rate review must be incorporated into the adjusted (rate year) equivalent bills calculation, and do not perform any rate reviews between rate cases." See Attachment 8 (Gregg Therrien, "22-041_2022-07-06_ENGI_ATT-TESTIMONY-MENARD.PDF", Bates page 1587).

Mr. Therrien's recommendation basically says to keep existing customers on the same rate schedule as the one they were on in the test year used to establish base rates, and to keep them there at least until the next rate case. DOE agrees.

Other Relevant Issues

Revenue Per Customer vs Total Revenue

Q24: How does RPC impact revenue decoupling vis-à-vis Total Revenue approach?

A24: When revenue is decoupled from volumetric sales, the revenue required by a utility to cover its expenses and earn a reasonable return is established. Fundamentally, decoupling is a mechanism designed to assure that a utility achieves the total allowed revenue by tracking the differences between actual and allowed revenue and adjusting customer bills up or down for any differences. Variants to this fundamental approach based on total allowed revenue include an allowed revenue per customer by design such as the RDAF used by Liberty. The allowed RPC design has the advantage of accommodating

000019

new customer growth by automatically adjusting total allowed revenue through a higher number of customers multiplied by allowed RPC.

However, RPC approaches have the disadvantage of being more complex since they introduce another factor in determining total allowed revenue. Any process that impacts the customer count in any decoupled rate class has the potential to materially impact total allowed revenue. In this testimony we have presented two such processes, the true up of equivalent bills and the reclassification of customer rates. Each of these processes has the potential to impact allowed revenue in a significant way. For this reason, DOE recommends that Liberty's decoupling mechanism be reviewed for ways to simplify and make it more transparent. One such way is to move from an RPC based decoupling mechanism to a total revenue based decoupling mechanism. This is an issue that DOE intends to explore further in Liberty 's next rate case when the decoupling provision can be changed.

RECAPITULATION

Q25: Please provide a summary of your discussion.

A25: As highlighted in this testimony, the current RDM design along with its significantly complicated underlying calculation, did not allow DOE to formulate a position on Liberty's current RDAF ask. The Department, instead, provides the following observations:

- Equivalent bill calculation, the True-up process, and the rate schedule reclassification – are some of the issues identified to be inherently linked to the calculation of overall $3,511,438 RDAF under-collection in DY4.

000020

- The true-up of estimated equivalent bills (i.e., the customer count), performed and presented by Liberty four months after any specific calendar month, represents a 4.4% increase in customer counts on average but accounts for 62%[23] of the RDAF revenue deficiency in DY4.

- Liberty performed three rate schedule reclassifications. In the context of revenue decoupling, this would impact allowed (i.e., target) revenues for the rate classes impacted by such reclassification and, thus, materially impact the overall revenue deficiency (excess) calculation.

- In the context of RDM design, Revenue Per Customer (RPC) approach introduces significant complexities. Total Revenue (TR) approach, on the other hand, retains most of the beneficial objectives of revenue decoupling without much of the complexities of an RPC approach.

- The prior period balance of $727,670 in RDAF deficiency from DY3, that is included in the overall $3.5 million under-collection, arguably, suffer from the same methodological issues as presented above.

- These methodological issues are significant in that they materially impact the RDAF over-/under-collection in any given decoupling year, and hence call for continued review of the RDM structure during the next rate case.

[23] That is, of the total DY4 RDAF deficiency of $2,783,768 (see page 2, Table 1b of the Technical Statement of Craig A. Holden, Tab 39 in DG 22-045), the deficiency due to true-ups amounts to $1,732,755 (see Attachment 9).

CONCLUSION

Q26: Does this conclude your testimony?

A26: Yes.

000022

ATTACHMENT 1

Educational and Professional Experience of Dr. Faisal Deen Arif

ATTACHMENT 2

Curriculum Vitae of Mark E. Thompson

ATTACHMENT 3

Liberty's response to Data Request Set 3, Response DOE 3-6 (March 23, 2023) in DG 22-041

ATTACHMENT 4

Liberty's response to Technical Session Data Request Set 1, Responses DOE TS 1-1 through TS 1-5 (attachments omitted) (May 30, 2023) in DG 22-045

ATTACHMENT 5

Liberty's response to Data Request Set 3, Response DOE 3-1 and DOE 3-2 (attachments omitted)(November 23, 2022) in DG 22-045

ATTACHMENT 6

DOE analysis of True-up numbers based on Liberty's response to Data Request Set 3 (November 23, 2022) and Technical Session Data Request Set 1 (May 30, 2023)

000023

ATTACHMENT 7

DG 20-105 Settlement Agreement, Revenue Decoupling Adjustment, Permanent Rates Revenue Per Customer (effective August 1, 2021), Exhibit 49, Bates page 036 (with analysis added by DOE)

ATTACHMENT 8

Recommendations by Gregg Therrien – submitted by Liberty on Jul. 6, 2022 in DG 22-041; see *Attachment – E. Menard*, file titled "22-041_2022-07-06_ENGI_ATT-TESTIMONY-MENARD.PDF", Bates page 1587 (PDF page 1501)

ATTACHMENT 9

DOE calculation at Attachment 9, p. 4 (Excel Tab titled "DOE Calculation Page 4") based on Liberty's Schedule 4 RDAF Revised 12/08/22.

ATTACHMENT 10

DOE analysis based on Liberty's response to Data Request Set 3 (November 23, 2022) and Technical Session Data Request Set 1 (May 30, 2023)

ATTACHMENT 11

List of Liberty Accounts affecting Adjusted Actual Revenue

000024

MD Faisal Deen Arif
(DEEN ARIF)
21 S. Fruit St., Suite 10, Room 235
Concord, N.H. 03301-2429
Work: 603-271-2441; Email: Faisal.DeenArif@energy.nh.gov

SUMMARY

• **Education:** Ph.D. (Economics) with specialization in Industrial Organization (Regulatory Pricing, Behavior of Public Enterprise, Competition Policy and Market Analysis); International Trade

• **Highlights of relevant professional experience across federal departments:** Experience working as an Administrator supervising a team of policy and data analysts of various ranks. Experience working at the Competition Bureau of Canada (equivalent to the Federal Trade Commission's Bureau of Competition) as well as the Federal Department for Innovation, Science and Economic Development (ISED) where, among others, I worked on market price setting regulations & policy design

- Extensive work experience and knowledge of the regulated industry and applicable laws, rules and regulations related rate setting and general engineering, economic and account issues/concepts
- Extensive experience in providing strategic advice and recommendations to senior executives (including Ministers, Deputy Ministers (DMs), Assistant DMs) on complex policy & program issues and technical factors
- Extensive experience in supervising and providing training for professional and technical staff in the study, analysis, research and reporting of regulatory and policy issues
- Significant experience in supervising and leveraging large amount of market and administrative data to perform behavioral analyses of regulated industry, forecasting rates/prices, and to prepare reports and exhibits to aid investigations, analyses, and appearance as expert witness before the Competition Tribunal (equivalent to the Commission)
- Extensive experience in advising counsel during cross-examination; presenting and defending staff position at proceedings before the Competition Tribunal/Commission; preparing briefing products in drafting Commission/Tribunal orders on substantive and administrative matters
- Experience in conferring with other agency administrators on administrative matters and agency policies and procedures
- Extensive experience in representing the Department at public and legislative meetings, public comment sessions, open forum meetings on regulatory policy issues, and technical sessions
- Demonstrated ability and extensive experience in establishing and maintaining continuous contact with external (e.g., other levels of governments, utility representatives, and the public) and internal officials/stakeholders (e.g., other units within and across the Departments/Ministries)

• **Highlight of professional experience in academia:** Extensive academic knowledge of economics and financial principles and practices in the field of public utilities and experience working at the Department of Economics, University of Ottawa as a Part-time Professor of Economics where I taught the following courses

- Engineering Economics – focusing on the accounting, engineering and economic factors involved in rate structure determination
- Microeconomic Theory and Applications – focusing on the structure of markets and economic principles
- Introduction to Microeconomics – emphasizing economic principles and applications

• **Knowledge:**

- Knowledge of the mission, structure and operations of the New Hampshire Department of Energy
- Knowledge of the general jurisdiction and statutory and regulatory framework
- Knowledge and experience leading negotiations on substantive industry issues related to
- competition and regulatory policy (e.g., advising lawyers for appearance before the Competition Tribunal, participating in expert technical sessions and in settlement conferences with regulated companies)
- Extensive experience in preparing and leading cabinet and executive documents (Memorandum to Federal Cabinet, Federal Budget Proposals, Briefing Notes and Executive Dockets for the Commissioner, Policy Papers, Policy Briefs)

• **Linguistic profile:** Excellent oral and written communication skills in both English and French

• **Personal traits:** Good management and interpersonal skills; great ability to mobilize people to achieve results; able to create vision and strategy by exercising creative analytical thinking; able to do proactive risk management; reliable, flexible, adaptable; strong commitment to learning and upholding integrity and respect; sound judgment and values & ethics

• **Professional recognition:**

- Departmental merit awards: Department of Employment and Social Development (ESDC) Deputy Ministers' Award of Excellence (2019), Treasury Board of Canada Secretariat (TBS) Merit Award (2017); Competition Bureau Commissioner’s Merit Award (2009)
- Branch merit award: ESDC Learning Branch Assistant Deputy Minister’s Award of Excellence in Policy Design (2019)
- Other award: Divisional special recognition for contribution to Federal Budget on price gap policy initiative, ISED (2014)

• **Professional goal:** to apply my Economics background and professional administrative experience to be able to effectively contribute towards sound stewardship of resources and public utilities regulation and management practices

000026

EDUCATION

- Ph.D., Economics, University of Ottawa, Ottawa, 2012 (duration 5 years)
  - Specialization in Industrial Organization (Regulatory Economics, Competition Policy and Markets)
- Graduate courses (Ph.D. level), Economics, University of Guelph, 2004 (duration 1 year)
- M.A., Economics, York University, Toronto, 2003 (duration 1.5 years)

EMPLOYMENT OVERVIEW

Director; Gas Division; New Hampshire Department of Energy (NHDOE)
June 2022 – to-date

- Lead the Gas Division at the NHDOE
- Provide direction to analysts working on matters related to various gas dockets before the Department
- Represent Departmental positions on gas dockets before the NH Public Utilities Commission (NHPUC)
- Coordinate communications and workflows among the Department and the regulated utility companies in New Hampshire
- Represent/coordinate Departmental position on gas matters with other State (e.g., other New England States) and federal regulators (e.g., the Federal Energy Regulatory Commission, FERC)
- Provide input in developing the NH Energy Policy
- Assist Departmental Senior Management (e.g., the Commissioner, Deputy Commissioner, Director of Regulatory Division) in performing regulatory and administrative functions

Manager; Repayment Portfolio; Planning, Integrity and Repayment Division; Canada Student Loans Program; Employment and Social Development Canada (with commensurate responsibilities that of the U.S. Department of Labor and the Department of Health, Education and Welfare)
June 2018 – June 2022

- Led strategic policy agenda and managed the secretarial support activities for the Federal-Provincial-Territorial (FPT) Committee on Repayment and Designation of the Canada Student Loans portfolio
- Led policy design and program delivery components of the Repayment Assistance Plan (RAP)
- Led policy design and modernization initiative for the Educational Institution Designation Policy Framework
- Led the program design, delivery and accountability of the Annual Strategic Incentives Plan (put in place to incentivize the third-party Service Provider responsible for disbursement and collection of Canada Student Loans)

000027

- Led and provided strategic policy and program support to integrated and non-integrated Provinces and Territories in administering governance function on the Service Provider contract
- Led a team of seven individuals including Policy and Data Analysts (EC-02 to EC-06) and Program Officers (PM-03 and PM-04)
- Set employee performance agreements (by creating vision and strategy to mobilize people and promote internal and external collaboration with partners and stakeholders for innovation and guiding change to achieve result), evaluated PAs at the year-end, ensured successful delivery of all work items for the team, hired new employees, and provided stewardship on financial responsibilities

**Advisor/Economist, Pensions and Benefits Sector, Treasury Board Secretariat (with equivalent
responsibilities that of the U.S. Department of Treasury)**
April 2014 to June 2018

- Led the Government side (on behalf of the Treasury Board as the employer of the Federal Public Service) in working group negotiations and discussions with the Bargaining Agents (including PSAC, PIPSC, ACFO)
- Acted as the Lead Expert Advisor (plan & program design) to and an employer-side member of two Joint Committees (between TBS & Professional Institute of Public Service of Canada (PIPSC); and TBS & Public Service Alliance of Canada (PSAC))
- Authored briefing notes, executive decks and fact sheets (e.g. one- and two-pagers) to provide specific policy advice to the Deputy Minister (DM), ADM, Senior Directors, Directors and other members of the senior management team
- Penned policy papers, summary notes and briefing materials for senior officials
- Authored detailed report on regulatory policy gap analysis on employee benefits and services
- Wrote a series of data notes (and performed extensive data analyses) to design and support negotiation strategy
- Attended TBS inter-sectoral senior management team meetings as an expert advisor on policy issues related to employee benefits and human resources policy obligations
- Reviewed multiple Treasury Board Submissions and performed the challenge function from the TBS Policy Centre

Economist/Policy Analyst, Strategic Policy Branch; Innovation, Science and Economic Development Canada (former Industry Canada – Equivalent to U.S. Department of Commerce)
April 2010 to April 2014

- Authored departmental budget proposal on the Government of Canada’s Price Gap policy initiative, featured in the Federal Budget 2014
- Held the pen on two Memoranda to the Cabinet (MC) on modernization of the Investment Canada Act (the national security provisions) and the relevant executive decks on the subject
- Participated and represented ISED at multiple interdepartmental meetings

000028

- Authored policy papers, issue notes, research papers, one- & two-page summary notes, stakeholder consultation reports and briefing notes for senior management (including Ministers, Deputy Minister (DM), ADMs, and DGs)
- Provided multiple written strategic advice and analyses to senior management on issues related to: international investment coming into Canada, marketplace competition, intellectual property rights and marketplace framework policy issues
- Prepared regulatory packages for publication in Canada Gazette Part II involving complex, technical issues pertaining to foreign investments coming into Canada, impacts on the markets and on regulatory pricing
- Coordinated Branch inputs for the Departmental Results Reports (DRR)
- Prepared Question Period cards for the Parliamentary Committees (i.e., for members of the House of Commons / Representatives) and coordinated dockets for the Minister
- Authored a number of analytical research papers and supported the implementation of the research projects under the Industry Canada-Canada Intellectual Property Office MOU
- Led the design of and organized the ISED Distinguished Speakers Series

Economist, Economic Policy and Enforcement Branch, Competition Bureau (with commensurate responsibilities that of the U.S. Department of Justice and the Federal Trade Commission)
July 2008-July 2009

- Analyzed regulatory pricing and utility policy, rate structures and design for the purpose of determining appropriate utility rates, rate structures and services, and enforcing market competition
- Prepared analyses of upstream & downstream market conditions and industry trends to make recommendations on appropriate product price structures and/or service changes
- Led negotiations on substantive industry issues in technical sessions and settlement conferences and coordinated internal and external consultations related to complex regulatory and anti-trust cases
- Conducted investigations and performed comprehensive, complicated and detailed research and analysis of past testimonies and exhibits submitted by regulated companies, and other parties, using information from various sources (such as written staff information requests, audits, prior Competition Tribunal orders, relevant publications and reviews of utility reports and tariffs emphasizing compliance with statutes, rules and Tribunal orders)
- Conferred with other executive personnel and administrators to develop policies and strategies to achieve policy and procedural goals and objectives and to meet statutory mandates
- Prepared lectures and presentations for national conferences and association meetings and institutes
- Assisted attorneys drafting proposals on remedial measures on complex regulatory and anti-trust cases to enforce regulations on behalf of the Competition Bureau
- Authored summary/opinion papers (i.e. briefing notes/memos summarizing the economic underpinning) on anti-trust issues related to regulatory pricing, mergers, dominance and abuse of market power, and civil matter cases
- Prepared written recommendations and provided oral briefings (as expert witness) to senior management on regulatory and competition issues (e.g., on market conditions and the state of

competition, remedial propositions, supply planning and other accounting, financing and planning matters)
- Prepared analytical report on the Generic Drug Market Study, Phase II, jointly coordinated with the Legislative and Parliamentary Affairs Branch at the Competition Bureau

---

LEADERSHIP EXPERIENCE

• Co-Champion, Learning Branch Accessibility Committee
September 2019 – June 2022
- Co-led the Accessibility Committee along with the DG, Canada Education Savings Program
- Provided strategic direction on planning, design and delivery of various accessibility-related events thoughout the year to raise workplace awareness

• Co-Chair, Young Professionals' Network (YPN), Strategic Policy Sector, Industry Canada
2013-2014
- Co-Chaired the Strategic Policy Sector-Young Professionals' Network
- Coach young professionals and promote learning and career growth opportunities for them

• Industry Canada Charitable Campaign Canvasser
2011-2012
- Met with colleagues to raise awareness of the Government of Canada Workplace Charitable
- Campaign (GCWCC) and encouraged coworkers to donate
- Created a culture of generosity and charity to support charitable causes.

• Vice-President (Finances), Graduate Students' Association Étudients Diplômes, University of Ottawa
2005-2007
- Managed the uOttawa Graduate Students' Association's annual budget (an envelope of $400,000 per annum)
- Led GSAÉD's financial support programs for the University of Ottawa grad students
- Led financial administration of GSAÉD
- Modernized and streamlined the preparation and presentation of financial reports and update, provided to the Governing Council of GSAÉD

REFERENCES

Available upon request

000030

MARK E. THOMPSON

Mark is President of Forefront Economics Inc. and has over 30 years of experience as an applied economist in the electric and natural gas utility industry. In 1993 Mark founded Forefront Economics (FE), an economics consulting company specializing in data organization and analysis services for natural gas and electric companies. Forefront Economics has conducted energy tracking and benchmarking, DSM planning and evaluation, load research, load forecasting, customer segmentation, demand modeling, and cost effectiveness analysis for energy clients. Mark has managed a variety of analytical projects to support regulatory and planning efforts for gas and electric utilities, including customer response modeling, market segmentation and profiling, and demand side planning and evaluation projects.

WORK EXPERIENCE

10/1993 - Present **_Forefront Economics Inc, Beaverton, Oregon_**
President
Responsibilities: Manage consulting practice specializing in econometric analysis and information delivery for energy utilities. Primary focus is on the use of econometric methods for load analysis, forecasting, program evaluation, market segmentation, and consumer predictive modeling.

8/1987 - 9/1993 **_Portland General Electric Company, Portland, Oregon_**
Senior Analyst, Rates and Regulatory Affairs Department
Responsibilities: Determine the economic impact of energy efficiency programs. Work with PGE, OPUC, BPA, ODOE, and NWPPC personnel to collaboratively develop plan for cost-efficient evaluation of DSM programs. Project Leader, Short-Term Forecast. Conduct economic analysis and forecasting. Project Leader on various market research projects.

8/1983 - 7/1987 **_Union Pacific Railroad Company, Omaha, Nebraska_**
Manager, Economic Forecasts
Responsibilities: Supervised a staff of three professional economists with the objective of developing the Marketing Department's forecast of Union Pacific's business levels; advised upper management of any potential impacts on business from changes in the economic climate; planned for staff training; and procured computer equipment and other resources.

7/1980 - 7/1983 **_Louisiana State University, Baton Rouge, Louisiana_**
Economic Analyst, Fishery Resources

000031

Responsibilities: Conducted economic research on fisheries at the state and national levels; developed econometric models for analysis of supply and demand conditions and market forecasting.

EDUCATION

June 1980 ***Master of Science, Agricultural and Natural Resource Economics***
Oregon State University, Corvallis, Oregon
Major Emphasis: Natural Resource Economics Minor: Statistics

May 1978 ***Bachelor of Science, Agricultural Economics***
Oklahoma State University, Stillwater, Oklahoma

PUBLICATIONS

Available upon request

CONTACT

3800 SW Cedar Hills Blvd, Suite 285 Beaverton OR 97005

Email: mark@forecon.com URL: www.forecon.com

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-041

Petition for Approval to Recover Revenue Decoupling Adjustment Factor Costs

Department of Energy Data Requests - Set 3

Date Request Received: 3/17/23
Request No. DOE 3-6 (Revised)

Date of Response: 3/23/23
Respondent: James Bonner

REQUEST:

Ref: Technical Session held on March 2, 2023.

Has Liberty undertaken any rate re-classifications or performed any inter-class migration among customer classes since the commencement of the RDAF mechanism as implemented on and after November 1, 2018? If yes, please provide details on such adjustments by rate class, by month, by year.

DOE 3-6 - Revised to Reduce the Number of Years Data Requested to 3 Years

COG Year 1: November 1, 2018 to October 31, 2019

Rate Class	Month	No. of Equivalent Bills prior to the adjustments	No. of Equivalent Bills after to the adjustments

COG Year 2: November 1, 2019 to October 31, 2020

Rate Class	Month	No. of Equivalent Bills prior to the adjustments	No. of Equivalent Bills after to the adjustments

000033

Docket No. DG 22-041 Request No. DOE 3-6 (Revised)

COG Year 3: November 1, 2020 to October 31, 2021

Rate Class	Month	No. of Equivalent Bills prior to the adjustments	No. of Equivalent Bills after to the adjustments

RESPONSE:

Yes. EnergyNorth ran its Rate Review process in June 2019, June 2020, and July 2021.

The Rate Review process is a computer-generated weather-normalized historical annual billing comparison for each customer of their present rate to one or more proposed rates based on the rate class eligibility criteria shown in the tariff rate schedules. The results are then manually reviewed by customer care personnel, and if the recommended change is determined to be appropriate, each affected customer is notified, and a rate change is made. The process was run annually starting January 2017, then each subsequent year, except for 2022, after the May financial closing to ensure that the annual comparison completely contains the most recent Winter Season billing for each customer.

The summary results of the computer-generated billing comparison and recommendations for 2019, 2020, and 2021 are shown in Attachments DOE 3-6.1, DOE 3-6.2, and DOE 3-6.3, respectively. The summary results consist of two tables: the left-hand table contains the annual revenue comparison; the right-hand table compares the annual normalized weather consumption to the actual consumption.

For the revenue comparison table, the first column with the rate identifier in bold is the current rate class and the non-bold rate identifier is the recommended rate class. The second column shows the number of customers affected. The third column is the expected annual distribution revenue for the affected customers in aggregate under the recommended rate at prices in effect when the Rate Review was run. The fourth column is the expected annual distribution revenue for the affected customers in aggregate under the customer's present rate at prices in effect when the Rate Review was run. The fifth and sixth columns contain the annual revenue difference and percent annual revenue difference between recommended and present rates. For the annual normalized weather consumption to the actual consumption table, the information is presented in the same fashion.

000034

Docket DG 22-045
Direct Testimony of Faisal Deen Arif
and Mark Thompson
Attachment 3
Page 3 of 5

Docket No. DG 22-041
Attachment DOE 3-6.1
Page 1 of 1

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Rate Review
Review Period Ending May 2019

Revenue Comparison

Row Labels	Customers	Sum of New_Amount	Sum of Cur_Amount	Difference	PctDiff
40-GC41	**252**	**$893,318**	**$718,233**	**$175,085**	**24.4%**
40-GC42	112	$694,890	$488,412	$206,478	42.3%
40-GC43	1	$41,232	$44,700	($3,467)	-7.8%
40-GC51	134	$134,949	$162,704	($27,754)	-17.1%
40-GC52	5	$22,246	$22,418	($172)	-0.8%
40-GC42	**114**	**$1,049,148**	**$1,411,277**	**($362,129)**	**-25.7%**
40-GC41	55	$162,688	$262,925	($100,237)	-38.1%
40-GC43	15	$545,544	$539,883	$5,661	1.0%
40-GC51	8	$16,426	$38,945	($22,518)	-57.8%
40-GC52	32	$222,323	$366,681	($144,358)	-39.4%
40-GC53	3	$76,856	$112,938	($36,083)	-31.9%
40-GC54	1	$25,311	$89,905	($64,594)	-71.8%
40-GC43	**21**	**$615,905**	**$799,023**	**($183,118)**	**-22.9%**
40-GC42	15	$312,436	$365,006	($52,570)	-14.4%
40-GC53	6	$303,469	$434,017	($130,547)	-30.1%
40-GC51	**97**	**$279,788**	**$190,963**	**$88,825**	**46.5%**
40-GC41	76	$111,073	$87,662	$23,411	26.7%
40-GC42	7	$46,063	$21,545	$24,518	113.8%
40-GC43	1	$66,808	$45,307	$21,501	47.5%
40-GC52	13	$55,843	$36,449	$19,394	53.2%
40-GC52	**50**	**$555,263**	**$446,824**	**$108,439**	**24.3%**
40-GC41	5	$13,628	$16,947	($3,319)	-19.6%
40-GC42	27	$286,518	$180,032	$106,485	59.1%
40-GC43	1	$30,725	$17,269	$13,456	77.9%
40-GC51	9	$20,153	$33,239	($13,086)	-39.4%
40-GC53	5	$151,608	$123,332	$28,276	22.9%
40-GC54	3	$52,630	$76,003	($23,373)	-30.8%
40-GC53	**12**	**$222,669**	**$302,529**	**($79,860)**	**-26.4%**
40-GC42	3	$35,431	$41,062	($5,631)	-13.7%
40-GC43	1	$54,200	$38,649	$15,551	40.2%
40-GC52	5	$65,827	$94,694	($28,867)	-30.5%
40-GC54	3	$67,211	$128,124	($60,913)	-47.5%
40-GC54	**9**	**$703,414**	**$331,439**	**$371,975**	**112.2%**
40-GC41	1	$2,210	$9,259	($7,048)	-76.1%
40-GC52	1	$6,596	$10,359	($3,762)	-36.3%
40-GC53	7	$694,608	$311,822	$382,786	122.8%
40-GR1	**84**	**$60,944**	**$46,350**	**$14,594**	**31.5%**
40-GR3	84	$60,944	$46,350	$14,594	31.5%
40-GR5	**4**	**$4,327**	**$3,246**	**$1,081**	**33.3%**
40-GR6	4	$4,327	$3,246	$1,081	33.3%
Grand Total	**643**	**$4,384,777**	**$4,249,885**	**$134,891**	**3.2%**

Weather Normalized to Actual Consumption Comparison

Row Labels	Customers	Sum of WN_Consumption	Sum of Recalc_Consumption_S	DiffConsump	PctDiffConsump
40-GC41	**252**	**1,719,198**	**1,743,606**	**(24,408)**	**-1.4%**
40-GC42	112	1,304,708	1,324,744	(20,036)	-1.5%
40-GC43	1	143,162	145,220	(2,058)	-1.4%
40-GC51	134	211,164	212,952	(1,789)	-0.8%
40-GC52	5	60,164	60,689	(525)	-0.9%
40-GC42	**114**	**3,871,191**	**3,915,045**	**(43,854)**	**-1.1%**
40-GC41	55	389,948	396,517	(6,569)	-1.7%
40-GC43	15	1,780,973	1,804,556	(23,584)	-1.3%
40-GC51	8	56,869	57,413	(544)	-0.9%
40-GC52	32	956,509	964,786	(8,277)	-0.9%
40-GC53	3	373,483	376,608	(3,125)	-0.8%
40-GC54	1	313,409	315,165	(1,756)	-0.6%
40-GC43	**21**	**2,826,357**	**2,850,676**	**(24,320)**	**-0.9%**
40-GC42	15	963,516	977,848	(14,332)	-1.5%
40-GC53	6	1,862,840	1,872,828	(9,988)	-0.5%
40-GC51	**97**	**658,351**	**663,772**	**(5,421)**	**-0.8%**
40-GC41	76	173,559	175,163	(1,604)	-0.9%
40-GC42	7	89,915	90,550	(635)	-0.7%
40-GC43	1	248,787	251,484	(2,697)	-1.1%
40-GC52	13	146,090	146,575	(485)	-0.3%
40-GC52	**50**	**2,265,906**	**2,280,948**	**(15,042)**	**-0.7%**
40-GC41	5	31,558	31,913	(355)	-1.1%
40-GC42	27	724,575	733,027	(8,452)	-1.2%
40-GC43	1	102,015	102,852	(838)	-0.8%
40-GC51	9	72,666	72,705	(40)	-0.1%
40-GC53	5	809,905	814,158	(4,252)	-0.5%
40-GC54	3	525,187	526,293	(1,106)	-0.2%
40-GC53	**12**	**1,526,191**	**1,532,860**	**(6,669)**	**-0.4%**
40-GC42	3	95,122	96,027	(905)	-0.9%
40-GC43	1	212,772	214,982	(2,210)	-1.0%
40-GC52	5	389,990	392,415	(2,425)	-0.6%
40-GC54	3	828,307	829,436	(1,129)	-0.1%
40-GC54	**9**	**4,890,357**	**4,920,817**	**(30,459)**	**-0.6%**
40-GC41	1	4,662	4,739	(77)	-1.6%
40-GC52	1	27,295	27,676	(381)	-1.4%
40-GC53	7	4,858,401	4,888,402	(30,001)	-0.6%
40-GR1	**84**	**82,872**	**84,138**	**(1,266)**	**-1.5%**
40-GR3	84	82,872	84,138	(1,266)	-1.5%
40-GR5	**4**	**4,721**	**4,825**	**(104)**	**-2.2%**
40-GR6	4	4,721	4,825	(104)	-2.2%
Grand Total	**643**	**17,845,143**	**17,996,687**	**(151,543)**	**-0.8%**

000035

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Rate Review
Review Period Ending May 2020

Revenue Comparison

Row Labels	Customers	Sum of New_Amount	Sum of Cur_Amount	Difference	PctDiff
40-GC41	**214**	**$717,998**	**$588,054**	**$129,944**	**22.1%**
40-GC42	91	$582,586	$410,170	$172,416	42.0%
40-GC51	120	$117,959	$154,958	($36,999)	-23.9%
40-GC52	3	$17,454	$22,926	($5,472)	-23.9%
40-GC42	**114**	**$784,820**	**$1,079,310**	**($294,489)**	**-27.3%**
40-GC41	60	$194,229	$306,192	($111,963)	-36.6%
40-GC43	8	$302,196	$298,111	$4,085	1.4%
40-GC51	9	$13,449	$38,367	($24,917)	-64.9%
40-GC52	35	$226,293	$366,479	($140,187)	-38.3%
40-GC53	2	$48,654	$70,161	($21,507)	-30.7%
40-GC43	**19**	**$555,300**	**$751,697**	**($196,397)**	**-26.1%**
40-GC42	11	$200,493	$241,365	($40,872)	-16.9%
40-GC52	1	$14,245	$25,312	($11,067)	-43.7%
40-GC53	7	$340,563	$485,020	($144,457)	-29.8%
40-GC51	**131**	**$292,092**	**$180,492**	**$111,600**	**61.8%**
40-GC41	115	$155,324	$117,409	$37,916	32.3%
40-GC42	3	$19,892	$7,097	$12,794	180.3%
40-GC43	1	$65,655	$30,272	$35,383	116.9%
40-GC52	12	$51,221	$25,714	$25,506	99.2%
40-GC52	**62**	**$514,797**	**$435,091**	**$79,706**	**18.3%**
40-GC41	2	$4,772	$6,345	($1,573)	-24.8%
40-GC42	28	$327,977	$201,828	$126,148	62.5%
40-GC43	1	$41,586	$24,402	$17,184	70.4%
40-GC51	27	$48,483	$98,675	($50,192)	-50.9%
40-GC53	2	$51,646	$40,225	$11,421	28.4%
40-GC54	2	$40,334	$63,616	($23,282)	-36.6%
40-GC53	**11**	**$304,531**	**$408,197**	**($103,667)**	**-25.4%**
40-GC42	1	$12,619	$14,367	($1,749)	-12.2%
40-GC43	3	$130,870	$95,472	$35,399	37.1%
40-GC52	3	$45,990	$63,500	($17,510)	-27.6%
40-GC54	4	$115,052	$234,858	($119,807)	-51.0%
40-GC54	**11**	**$1,042,766**	**$467,647**	**$575,119**	**123.0%**
40-GC43	1	$49,533	$19,140	$30,393	158.8%
40-GC53	10	$993,232	$448,506	$544,726	121.5%
40-GR1	**108**	**$78,958**	**$60,085**	**$18,873**	**31.4%**
40-GR3	108	$78,958	$60,085	$18,873	31.4%
40-GR5	**6**	**$5,290**	**$4,056**	**$1,234**	**30.4%**
40-GR6	6	$5,290	$4,056	$1,234	30.4%
Grand Total	**676**	**$4,296,552**	**$3,974,630**	**$321,923**	**8.1%**

Weather Normalized to Actual Consumption Comparison

Row Labels	Customers	Sum of WN_Consumption	Sum of Recalc_Consumption_S	DiffConsump	PctDiffConsump
40-GC41	**214**	**1,367,512**	**1,308,393**	**59,119**	**4.5%**
40-GC42	91	1,087,749	1,032,640	55,109	5.3%
40-GC51	120	213,507	210,806	2,700	1.3%
40-GC52	3	66,257	64,947	1,310	2.0%
40-GC42	**114**	**2,631,681**	**2,540,784**	**90,898**	**3.6%**
40-GC41	60	473,146	449,365	23,782	5.3%
40-GC43	8	972,839	927,455	45,384	4.9%
40-GC51	9	50,442	49,877	565	1.1%
40-GC52	35	907,934	891,214	16,720	1.9%
40-GC53	2	227,320	222,873	4,447	2.0%
40-GC43	**19**	**2,752,851**	**2,688,903**	**63,948**	**2.4%**
40-GC42	11	592,945	563,088	29,857	5.3%
40-GC52	1	86,596	86,554	42	0.0%
40-GC53	7	2,073,310	2,039,261	34,049	1.7%
40-GC51	**131**	**633,027**	**612,369**	**20,658**	**3.4%**
40-GC41	115	217,710	210,007	7,703	3.7%
40-GC42	3	38,520	36,376	2,144	5.9%
40-GC43	1	248,847	240,142	8,705	3.6%
40-GC52	12	127,950	125,845	2,105	1.7%
40-GC52	**62**	**1,915,722**	**1,876,117**	**39,605**	**2.1%**
40-GC41	2	10,258	9,911	347	3.5%
40-GC42	28	847,644	821,417	26,227	3.2%
40-GC43	1	152,234	148,227	4,007	2.7%
40-GC51	27	214,875	212,538	2,337	1.1%
40-GC53	2	254,354	252,266	2,088	0.8%
40-GC54	2	436,357	431,757	4,600	1.1%
40-GC53	**11**	**2,367,653**	**2,340,514**	**27,140**	**1.2%**
40-GC42	1	33,603	32,043	1,560	4.9%
40-GC43	3	484,448	471,431	13,017	2.8%
40-GC52	3	275,060	271,249	3,811	1.4%
40-GC54	4	1,574,542	1,565,790	8,752	0.6%
40-GC54	**11**	**7,288,269**	**7,222,430**	**65,839**	**0.9%**
40-GC43	1	157,587	141,936	15,651	11.0%
40-GC53	10	7,130,683	7,080,494	50,189	0.7%
40-GR1	**108**	**105,848**	**100,098**	**5,751**	**5.7%**
40-GR3	108	105,848	100,098	5,751	5.7%
40-GR5	**6**	**5,322**	**5,057**	**265**	**5.2%**
40-GR6	6	5,322	5,057	265	5.2%
Grand Total	**676**	**19,067,887**	**18,694,665**	**373,222**	**2.0%**

000036

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Rate Review
Review Period Ending May 2021

Revenue Comparison

Row Labels	Customers	Sum of New_Amount	Sum of Cur_Amount	Difference	PctDiff
40-GC41	**301**	**$1,118,025**	**$909,746**	**$208,279**	**22.9%**
40-GC42	135	$907,816	$650,967	$256,849	39.5%
40-GC51	160	$175,243	$214,690	($39,447)	-18.4%
40-GC52	6	$34,967	$44,090	($9,123)	-20.7%
40-GC42	**186**	**$1,172,249**	**$1,605,675**	**($433,425)**	**-27.0%**
40-GC41	127	$396,444	$633,991	($237,546)	-37.5%
40-GC43	12	$490,702	$490,724	($22)	0.0%
40-GC51	12	$19,855	$48,470	($28,615)	-59.0%
40-GC52	34	$235,948	$387,801	($151,853)	-39.2%
40-GC53	1	$29,300	$44,690	($15,389)	-34.4%
40-GC43	**14**	**$278,573**	**$360,685**	**($82,112)**	**-22.8%**
40-GC42	11	$197,811	$242,546	($44,734)	-18.4%
40-GC52	1	$5,305	$13,184	($7,879)	-59.8%
40-GC53	2	$75,456	$104,955	($29,499)	-28.1%
40-GC51	**224**	**$536,871**	**$381,592**	**$155,279**	**40.7%**
40-GC41	195	$284,435	$227,108	$57,327	25.2%
40-GC42	11	$92,174	$45,653	$46,521	101.9%
40-GC43	1	$85,999	$61,100	$24,899	40.8%
40-GC52	17	$74,262	$47,730	$26,532	55.6%
40-GC52	**119**	**$930,237**	**$717,758**	**$212,480**	**29.6%**
40-GC41	22	$60,701	$76,375	($15,675)	-20.5%
40-GC42	61	$694,375	$433,347	$261,028	60.2%
40-GC51	33	$73,608	$123,116	($49,508)	-40.2%
40-GC53	3	$101,553	$84,919	$16,634	19.6%
40-GC53	**12**	**$270,358**	**$384,438**	**($114,080)**	**-29.7%**
40-GC42	1	$15,120	$15,676	($556)	-3.5%
40-GC43	2	$84,760	$62,115	$22,645	36.5%
40-GC52	5	$63,220	$93,079	($29,859)	-32.1%
40-GC54	4	$107,257	$213,567	($106,309)	-49.8%
40-GC54	**12**	**$1,071,945**	**$486,804**	**$585,141**	**120.2%**
40-GC41	1	$3,126	$9,746	($6,620)	-67.9%
40-GC43	1	$53,110	$20,504	$32,606	159.0%
40-GC53	10	$1,015,709	$456,553	$559,156	122.5%
40-GR1	**140**	**$106,082**	**$80,577**	**$25,505**	**31.7%**
40-GR3	140	$106,082	$80,577	$25,505	31.7%
40-GR5	**13**	**$12,007**	**$9,183**	**$2,824**	**30.7%**
40-GR6	13	$12,007	$9,183	$2,824	30.7%
Grand Total	**1,021**	**$5,496,347**	**$4,936,457**	**$559,891**	**11.3%**

Weather Normalized to Actual Consumption Comparison

Row Labels	Customers	Sum of WN_Consumption	Sum of Recalc_Consumption_S	DiffConsump	PctDiffConsump
40-GC41	**301**	**2,134,930**	**2,005,817**	**129,113**	**6.4%**
40-GC42	135	1,711,850	1,593,141	118,710	7.5%
40-GC51	160	299,171	292,256	6,915	2.4%
40-GC52	6	123,909	120,420	3,489	2.9%
40-GC42	**186**	**3,681,914**	**3,472,919**	**208,995**	**6.0%**
40-GC41	127	930,928	868,399	62,529	7.2%
40-GC43	12	1,582,429	1,468,498	113,930	7.8%
40-GC51	12	56,516	54,705	1,811	3.3%
40-GC52	34	967,109	941,051	26,058	2.8%
40-GC53	1	144,931	140,265	4,666	3.3%
40-GC43	**14**	**1,010,493**	**961,011**	**49,482**	**5.1%**
40-GC42	11	572,672	531,516	41,155	7.7%
40-GC52	1	19,425	18,127	1,298	7.2%
40-GC53	2	418,396	411,368	7,028	1.7%
40-GC51	**224**	**1,129,296**	**1,072,271**	**57,026**	**5.3%**
40-GC41	195	420,997	399,543	21,454	5.4%
40-GC42	11	198,775	186,913	11,861	6.3%
40-GC43	1	326,544	306,417	20,127	6.6%
40-GC52	17	182,981	179,397	3,584	2.0%
40-GC52	**119**	**2,679,695**	**2,571,852**	**107,843**	**4.2%**
40-GC41	22	136,038	128,560	7,479	5.8%
40-GC42	61	1,731,080	1,645,615	85,465	5.2%
40-GC51	33	252,945	246,775	6,170	2.5%
40-GC53	3	559,631	550,902	8,729	1.6%
40-GC53	**12**	**2,102,187**	**2,080,828**	**21,359**	**1.0%**
40-GC42	1	41,549	38,940	2,609	6.7%
40-GC43	2	304,400	295,895	8,505	2.9%
40-GC52	5	352,976	347,051	5,925	1.7%
40-GC54	4	1,403,263	1,398,942	4,321	0.3%
40-GC54	**12**	**7,141,715**	**7,031,834**	**109,881**	**1.6%**
40-GC41	1	7,422	6,839	583	8.5%
40-GC43	1	201,755	193,079	8,675	4.5%
40-GC53	10	6,932,539	6,831,915	100,623	1.5%
40-GR1	**140**	**140,294**	**130,819**	**9,475**	**7.2%**
40-GR3	140	140,294	130,819	9,475	7.2%
40-GR5	**13**	**11,949**	**11,085**	**864**	**7.8%**
40-GR6	13	11,949	11,085	864	7.8%
Grand Total	**1,021**	**20,032,474**	**19,338,435**	**694,038**	**3.6%**

000037

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-045

Winter 2022–2023 and Summer 2023 Cost of Gas

Department of Energy Technical Session Data Requests - Set 1

Date Request Received: 5/19/23
Request No. DOE TS 1-1

Date of Response: 5/30/23
Respondent: Erin O'Brien

REQUEST:

Re: RDAF

Reference: technical session discussions held on May 9, 2023. Please provide a narrative description of Liberty Gas's process for calculating True-up for any given month. As an illustrative example, please use August 2022 actual (Tab titled "AugAdj 2022" in the excel file "Aug22 57. 46-Decoupling Entry -August 2022 & Tru Up EO review.xlsx") and August true-up (Tab titled "August Tru Up" in the same excel file).

For the illustrative month of August 2022, and for "AugAdj 2022" tab, please confirm that the tab references true-up data over April 2022 to August 2022 and not data over August 2022 to December 2022. If unable to confirm this understanding, please explain further, and provide an illustrative example and please provide any missing data.

Reference: Excel file "Aug22 57. 46-Decoupling Entry -August 2022 & Tru Up EO review.xlsx"). Please indicate where the final trued-up equivalent bills can be found for any given month (i.e., for example, for the month of August 2022, in which month will the true up equivalent bills show up?) Please provide all true-up data for all relevant months spanning Decoupling Year 3 and Year 4 (i.e., data related to creating final trued-up equivalent bills for the time period spanning September 1, 2020 to August 31, 2022).

RESPONSE:

At each month end, the initial decoupling calculation is performed based on the best information available during our 5-workday month-end close. As a result of cycle billing, most revenue pertaining to the month being closed is included in unbilled revenue, an estimate of the revenue not yet billed. In the subsequent months, the number of equivalent bills for that period is determined and is no longer estimated. The true up calculation is performed to record the results using the benefit of hindsight and true up the estimates initially recorded.

In the example of August 2022, the "AugAdj 2022" tab includes the estimates for unbilled revenue in Columns E ("# of Cust," number of equivalent bills in the estimated unbilled revenues recorded) and Column F ("Revenue," the Revenue Per Customer (RPC) as approved multiplied by the number of equivalent bills in Column E). This estimate is then carried into the "August

000038

Tru Up" tab to be compared to the actual results that pertain to August as determined in subsequent months.

As discussed in the May 9, 2023, technical session, the "August Tru Up" tab in the file provided was a placeholder. This Excel file was provided in September 2022 and we did not have the actual results for August at that time. If an earlier example is used, for example, the "Aug22 entry 56. 42-Decoupling Entry -April 2022 & Tru Up" file, you will see this represents the April 2022 calendar month decoupling results, for which we recorded the final true up in August 2022. In this example, the unbilled revenue estimates are brought into Columns C and D of the "Apr Tru Up" tab. You will see that these match Columns E and F of the "Apr Adj 2022" tab (those columns are discussed above). Then, the actuals are recorded in subsequent columns. If you scroll down to row 40 and below of the "Apr Tru Up" tab, you will see the actual results for April coming through in the May, June, July, and August equivalent bill data. As discussed, the first two months following include the bulk of the information. We have determined that four months is an appropriate adjustment period to capture the actual results in a reasonable amount of time (rather than extending this to pick up smaller adjustments that are not material).

As discussed above, the "Aug Adj 2022" tab includes the information available during the August close (i.e., through September 8, 2022, workday 5). The "August Tru Up" tab is a placeholder for the company as these are our working files. At the time this file was provided (September 2022), the data through December was not yet available. An illustrative example is included in (a) above.

The four months of true ups for May, June, July, and August 2022 (recorded in September, October, November, and December 2022, respectively) are included in Attachment DOE TS 1-1.zip

The final trued up bills will be found in the fourth month following the calendar month. As discussed above, the April 2022 true ups were finalized in August. When these files were provided in September 2022, the information for true ups available at that time were provided. As a result of timing of the filing, the May, June, July, and August 2022 true ups were not yet complete. They have since been completed and are included in Attachment DOE TS 1-1.zip as noted above.

000039

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-045

Winter 2022–2023 and Summer 2023 Cost of Gas

Department of Energy Technical Session Data Requests - Set 1

Date Request Received: 5/19/23
Request No. DOE TS 1-2

Date of Response: 5/30/23
Respondent: Erin O'Brien

REQUEST:

Reference: Excel file "Aug22 57. 46-Decoupling Entry -August 2022 & Tru Up EO review.xlsx"). Please provide source data that identify calculation of the Equivalent Bills for Decoupling Year 3 (DY3) and Year 4 (DY4) (i.e., time period spanning September 1, 2020 to August 31, 2022). Due to Liberty Gas's accounting practice that take multiple (i.e., four or more) months to true-up an estimated number of equivalent bills for any given month, please include all appropriate data that would clearly identify verifiable data (i.e., source data) for all months within the DY3 and DY4 timeframe.

RESPONSE:

Please refer to the "Monthly Delivery Sheets" files provided for EnergyNorth and Keene for DY4. Please note these files have multiple tabs and each month is layered on. Therefore, if you look at the August 2022 Monthly Delivery Sheet, it will include Calendar Month Delivery Service Bills by Month for all periods from September 2020 through August 2022.

As discussed, the Monthly Delivery Sheets are based on bills sent. Therefore, due to cycle billing, the current month will not capture most customer bills related to that month. This can be seen on each tab as the prior month's bills are consistently larger due to the timing of cycle billing weighting to early in each month.

Please see Attachment DOE TS 1-2.xlsx for Delivery Sheets not previously provided (September 2022 through December 2022).

000040

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-045

Winter 2022–2023 and Summer 2023 Cost of Gas

Department of Energy Technical Session Data Requests - Set 1

Date Request Received: 5/19/23	Date of Response: 5/30/23
Request No. DOE TS 1-3	Respondent: Erin O'Brien

REQUEST:

Reference: excel file "Aug22 57. 46-Decoupling Entry -August 2022 & Tru Up EO review.xlsx"), Tab "AugAdj 2022" and Tab "Low Income Aug". For Decoupling Year 3 and Year 4 time period (i.e., time period spanning September 1, 2020 to August 31, 2022), please identify Gas Assistance Program (GAP) data that clearly separates revenues collected through the GAP component of LDAC into the following two categories – revenues collected from base distribution rates, and revenues collected from Cost of Gas (COG) passthrough. Please provide supporting documentation.

RESPONSE:

Please refer to Attachment DOE TS 1-3.xlsx. The "Back up" tab includes details from the Bills and Volumes report derived from the revenue system. This report is sorted for GAP customers (R-4 and R7, as applicable) and components of revenue are broken down into fixed, variable and gas supply (pass-through). The "Journal Entry" tab of this attachment is the support provided in the "Low Income Aug" tab of the Excel file "Aug22 57. 46-Decoupling Entry -August 2022 & Tru Up EO review.xlsx." The decoupling calculation only picks up the fixed and variable portions of the journal entry for the purposes of decoupling.

000041

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-045

Winter 2022–2023 and Summer 2023 Cost of Gas

Department of Energy Technical Session Data Requests - Set 1

Date Request Received: 5/19/23	Date of Response: 5/30/23
Request No. DOE TS 1-4	Respondent: James Bonner

REQUEST:

Re: RDAF

a) Reference: Docket DG 22-041, Liberty Gas's Response to DOE DR 3-6. Liberty Gas's response to DOE 3-6 indicates that the Company ran rate reviews in June 2019, June 2020 and July 2021 resulting in customer migrations between rate classes. In the context of Decoupling Year 3 (spanning September 1, 2020 to August 31, 2021), please explain how such migration would impact the monthly decoupling revenue targets and the corresponding actual revenues. Please also explain how migration impacts the target and actual revenues when true-up process is completed after multiple (i.e., four or more) months.

b) Reference: Liberty Gas's Response to DOE 6-8. In its response to DOE 6-8 in Data Request Set 6 (part two), Liberty Gas indicated that the Company did not perform a rate review in 2022. Please explain why not.

RESPONSE:

a) Migration—meaning the movement of customers from one rate class to another—has no effect on the monthly decoupling target revenues (a.k.a. allowed revenues) or actual revenues. An individual customer's contribution to both is determined by the customer's rate class at the time the calculation is made. For example, a customer is not a Rate G-42 customer for the target revenue calculation and Rate G-43 customer for the allowed revenue calculation; they are in the same rate class for both. This is true even if the rate change takes place in the middle of the month. The customer's total equivalent bills and billed volume will be correctly apportioned between the two rates in the billing system. For the same reason, migration has no effect on the true-up process. The true-up process simply substitutes an actual measurement of the equivalent bills for a given month for the estimate originally used for the target revenue calculation at the time the decoupling entry was made.

b) In the late spring of 2022, the Company's available billing resources were heavily engaged in both the later stages of the Customer First SAP billing conversion design and testing processes as well as operating the current Cogsdale billing system. Although it was not intentional, the existing Rate Review process was simply overlooked during this extremely busy period.

000043

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-045

Winter 2022–2023 and Summer 2023 Cost of Gas

Department of Energy Technical Session Data Requests - Set 1

Date Request Received: 5/19/23	Date of Response: 5/30/23
Request No. DOE TS 1-5	Respondent: Erica Menard

REQUEST:

Reference: Review of ENNG's Revenue Decoupling Mechanism (Concentric Report by Gregg Therrien from August 8, 2019) in DG 22-041 Attachment of ELM-1 at Bates 1574; also found at DG 20-105, Exhibit 39. The Report states "The large RDM credit is unanticipated because the "real time" WNA is billed monthly on each customer's bill, thereby eliminating the largest anticipated variance component of the RDM, weather." Given this statement, please provide Liberty Gas's understanding of the reasons for decoupling adjustments in DY4 in excess of $3 million.

RESPONSE:

As filed on December 8, 2022, the revenue decoupling adjustment factor for the residential class includes a prior period under-recovery associated with the previous LDAC year's RDAF rate of $0.3 million plus a revenue deficiency of $2.6 million for the current decoupling year 4. The revenue decoupling adjustment factor for the commercial class includes a prior period under-recovery associated with the previous LDAC year's RDAF rate of $0.4 million plus a revenue deficiency of $0.2 million for the current decoupling year 4.

The reasons for the decoupling year 4 revenue deficiency of $2.6 million for the residential group and $0.2 million for the commercial group are generally attributable to factors such as energy conservation, economic effects, and other variables. As described in the Company's previous response to DOE 1-4 (b) and DOE 2-3 (b), the methodology for comparing actual revenues to allowed revenues does not explicitly quantify the under-recovery into the various categories.

000044

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-045

Winter 2022–2023 and Summer 2023 Cost of Gas
(COG and LDAC)

Department of Energy Data Requests - Set 3

Date Request Received: 10/27/22
Request No. DOE 3-1

Date of Response: 11/23/22
Respondent: Craig Holden

REQUEST:

Reference: LDAC filing (August 2, 2022), Supplemental LDAC filing (September 1) COG filing (dated September 1, 2022, filed September 2, 2022) and Updated filing (October 7, 2022) (hereinafter "COG filing" unless otherwise specified), and all Liberty EnergyNorth responses to data requests filed to date particularly Liberty's response to DOE DR Set 1 (including supplemental response filed on September 8, 2022).

Using the same Excel format used in Liberty's September 8, 2022 supplemental response to DOE DR Set 1, please define and provide information on allowed (or target) revenue and actual revenue for *regular monthly reconciliation* that occurs every month for the period September 2021 through August 2022. For the purposes of (audit) verification, please identify the relevant accounting entries for the actual revenue figures.

(If the information has already been provided in this or other docket(s), please clearly identify the source and the timeframe when it was provided, and a citation to allow DOE to review it, or attach a copy.)

Please provide live Excel files that correspond to any tables and schedules provided "Live" files should include the formulas and allow the user to input new figures, if needed.

RESPONSE:

Please see Attachment DOE 3-1.zip for the files that support the regular monthly reconciliation for the period September 2021 through August 2022. Within the .zip file, there are folders for both EnergyNorth (EN Decoupling Mnthly Adj Sept21 – Aug22) and Keene (KN Decoupling Mnthly Adj Sept21 – Aug22). Within each folder, there are two Excel workbooks and two PDF documents per month. Using January 2022 as an example, here are the four files with a brief description of each.

- Jan22 30. 39-Decoupling Entry -January 2022 & Tru Up.xlsx – Calculation of the monthly decoupling journal entry.

Docket No. DG 22-045 Request No. DOE 3-1

- Jan22 30. Egy_BillCalMo(Delv)_202201.pdf – Bill input support for the decoupling journal entry.
- Jan22 30. EN Jan 2022 Revenue Review CT 02.02.22.pdf – Revenue input support for the journal entry.
- Jan22 30. ENN Unbilled Accrual Entry - January 2022 CT review 02.07.22.xlsx – Calculation of the monthly unbilled revenue journal entry.

000046

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 22-045

Winter 2022–2023 and Summer 2023 Cost of Gas
(COG and LDAC)

Department of Energy Data Requests - Set 3

Date Request Received: 10/27/22	Date of Response: 11/23/22
Request No. DOE 3-2	Respondent: Craig Holden

REQUEST:

Reference: COG filing

Using the same Excel format used in Liberty's September 8, 2022 supplemental response to DOE DR Set 1 please define and provide information on allowed (or target) revenue and actual revenue for *true-up reconciliation* that occurs four months after a given month (i.e., based on Liberty's earlier filing, it appears, that e.g., for the month of October 2021, the true-up reconciliation would occur in February 2022) for the period September 2021 through August 2022. If actual data is not available, please identify it accordingly and provide a narrative explanation as to when such data will be available. For all actual data, please identify the relevant accounting entries.

(If the information has already been provided in this or other docket(s), please clearly identify the source and the timeframe when it was provided, and a citation to allow DOE to review it, or attach a copy.)

Please provide live Excel files that correspond to any tables and schedules provided "Live" files should include the formulas and allow the user to input new figures, if needed.

RESPONSE:

Please see Attachment DOE 3-2.zip for the files that support the true-up reconciliation for the period September 2021 through August 2022. Within the .zip file, there are folders for both EnergyNorth (EN Decoupling True ups Sept21 – Aug22) and Keene (KN Decoupling True ups Sept21 – Aug22). Within each folder, there are two Excel workbooks per month. Using January 2022 as an example, here are the two files with a brief description of each.

- Jan22 entry 29. 35-Decoupling Entry -September 21 & Tru Up.xlsx – Refer to the month's "Tru up" tab for the calculation of four months of true-ups following the monthly decoupling journal entry. In this example, the final true-up entry posted in January relates to equivalent customer bills for September 2021.

000047

Docket No. DG 22-045 Request No. DOE 3-2

- Jan22 29. Monthly Delivery Sheets - ENergy North.xlsx – Monthly delivery sheet breaking out the equivalent customer bills by the period (month) to which the bill relates.

000048

Attachment 6: DOE Analysis of True-up Numbers

Source: based on Liberty's response to Data Request Set 3 (November 23, 2022) and Technical Session Data Request Set 1 (May 30, 2023)

Propensity of True-up Movement

ENNE + Keene - Analysis by count

	Count	%
Higher	170	98%
Lower	4	2%
Total	174	100%

ENNE - Analysis by count

	Count	%
Higher	118	98%
Lower	2	2%
Total	120	100%

Keene - Analysis by count

	Count	%
Higher	52	96%
Lower	2	4%
Total	54	100%

Error in Estimation

ENNE + Keene - Avg Pct Chg

	ENNE - Res.	ENNE - C&I
Total Estimated	710,329	105,856
Diff from Forecast	17,213	4,708
Pct Error	2.4%	**4.4%**
Avg Error	2.7%	

ENNE - Avg Pct Chg

	ENNE - Res.	ENNE - C&I
Total Estimated	707,253	104,748
Diff from Forecast	17,092	4,665
Pct Error	2.4%	**4.5%**
Avg Error	2.7%	

Keene - Avg Pct Chg

	ENNE - Res.	ENNE - C&I
Total Estimated	3,076	1,108
Diff from Forecast	122	43
Pct Error	4.0%	**3.9%**
Avg Error	3.9%	

000049

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Docket DG 20-105
Revenue Decoupling Adjustment
Rates Eff. 8/1/2021

Docket N0. DG 20-105
Appendix 7
Page 1 of 1

Permanent Rates
Revenue Per Customer

Rate Class	January	February	March	April	May	June	July	August	September	October	November	December
R-1/5	$ 26.014	$ 25.540	$ 24.307	$ 22.609	$ 20.956	$ 19.755	$ 18.931	$ 19.019	$ 19.435	$ 20.546	$ 22.982	$ 25.299
R-3/6	$ 97.157	$ 93.255	$ 74.713	$ 50.567	$ 34.034	$ 25.472	$ 22.948	$ 23.085	$ 25.352	$ 37.025	$ 62.207	$ 83.921
R-4/7	$ 97.157	$ 93.255	$ 74.713	$ 50.567	$ 34.034	$ 25.472	$ 22.948	$ 23.085	$ 25.352	$ 37.025	$ 62.207	$ 83.921
G-41/44	$ 235.956	$ 226.979	$ 184.606	$ 128.146	$ 88.800	$ 70.623	$ 66.093	$ 66.385	$ 70.916	$ 94.488	$ 154.776	$ 204.268
G-42/45	$ 1,578.472	$ 1,524.667	$ 1,241.555	$ 855.091	$ 523.642	$ 346.741	$ 294.872	$ 301.796	$ 360.170	$ 572.697	$ 1,034.777	$ 1,394.253
G-43/46	$ 8,928.306	$ 8,426.278	$ 7,012.866	$ 4,981.917	$ 1,969.310	$ 1,450.046	$ 1,304.759	$ 1,372.855	$ 1,462.191	$ 2,016.955	$ 5,871.987	$ 7,656.083
G-51/55	$ 133.825	$ 130.979	$ 121.907	$ 111.427	$ 104.493	$ 98.646	$ 94.516	$ 98.006	$ 98.750	$ 101.809	$ 115.084	$ 126.203
G-52/56	$ 731.471	$ 706.568	$ 650.770	$ 576.938	$ 402.135	$ 377.110	$ 367.473	$ 377.804	$ 384.365	$ 407.882	$ 611.436	$ 669.830
G-53/57	$ 6,797.367	$ 6,197.111	$ 5,755.166	$ 4,877.206	$ 2,508.532	$ 2,307.268	$ 2,328.947	$ 2,476.034	$ 2,356.654	$ 2,625.619	$ 5,366.438	$ 6,077.525
G-54/58	$ 3,719.928	$ 3,726.283	$ 3,387.343	$ 3,833.707	$ 2,775.284	$ 2,874.002	$ 2,966.625	$ 3,090.866	$ 2,982.545	$ 2,965.834	$ 4,662.611	$ 3,822.712

Step Increase
Revenue Per Customer

Rate Class	January	February	March	April	May	June	July	August	September	October	November	December
R-1/5	$ 1.483	$ 1.402	$ 1.264	$ 0.987	$ 0.742	$ 0.563	$ 0.464	$ 0.461	$ 0.537	$ 0.767	$ 1.196	$ 1.535
R-3/6	$ 4.968	$ 4.490	$ 3.576	$ 2.178	$ 1.178	$ 0.590	$ 0.464	$ 0.462	$ 0.630	$ 1.405	$ 3.017	$ 4.353
R-4/7	$ 4.968	$ 4.490	$ 3.576	$ 2.178	$ 1.178	$ 0.590	$ 0.464	$ 0.462	$ 0.630	$ 1.405	$ 3.017	$ 4.353
G-41/44	$ 10.371	$ 9.551	$ 7.771	$ 5.376	$ 3.848	$ 2.999	$ 2.860	$ 2.877	$ 3.115	$ 4.296	$ 6.950	$ 9.342
G-42/45	$ 71.556	$ 65.275	$ 52.763	$ 33.854	$ 20.781	$ 13.163	$ 11.663	$ 12.053	$ 14.984	$ 26.315	$ 47.308	$ 64.023
G-43/46	$ 322.176	$ 307.458	$ 260.216	$ 188.058	$ 125.272	$ 80.674	$ 74.052	$ 74.222	$ 90.747	$ 148.398	$ 230.190	$ 306.060
G-51/55	$ 6.156	$ 6.082	$ 5.241	$ 4.545	$ 4.182	$ 4.099	$ 4.023	$ 4.113	$ 4.243	$ 4.825	$ 5.232	$ 5.946
G-52/56	$ 31.400	$ 30.740	$ 24.341	$ 20.081	$ 17.238	$ 17.150	$ 17.025	$ 17.535	$ 18.199	$ 21.044	$ 23.978	$ 27.933
G-53/57	$ 246.248	$ 243.066	$ 214.654	$ 186.181	$ 150.341	$ 140.629	$ 138.297	$ 140.255	$ 144.706	$ 168.388	$ 188.258	$ 211.553
G-54/58	$ 138.456	$ 145.419	$ 124.103	$ 143.307	$ 136.199	$ 145.470	$ 155.194	$ 160.877	$ 160.145	$ 160.192	$ 161.125	$ 137.154

Total
Revenue Per Customer

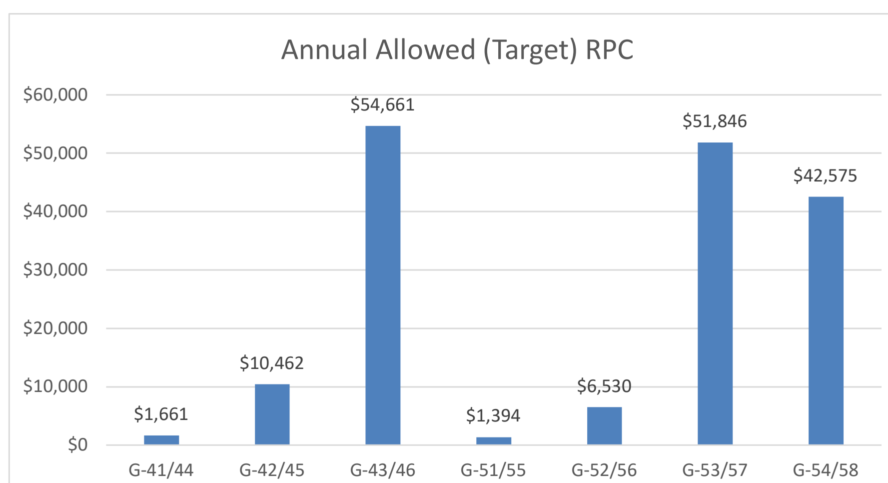
Rate Class	January	February	March	April	May	June	July	August	September	October	November	December
R-1/5	$ 27.498	$ 26.942	$ 25.571	$ 23.596	$ 21.698	$ 20.318	$ 19.395	$ 19.480	$ 19.972	$ 21.314	$ 24.178	$ 26.834
R-3/6	$ 102.124	$ 97.745	$ 78.289	$ 52.745	$ 35.212	$ 26.062	$ 23.412	$ 23.547	$ 25.982	$ 38.431	$ 65.224	$ 88.274
R-4/7	$ 102.124	$ 97.745	$ 78.289	$ 52.745	$ 35.212	$ 26.062	$ 23.412	$ 23.547	$ 25.982	$ 38.431	$ 65.224	$ 88.274
G-41/44	$ 246.326	$ 236.530	$ 192.376	$ 133.522	$ 92.648	$ 73.622	$ 68.954	$ 69.262	$ 74.031	$ 98.783	$ 161.726	$ 213.610
G-42/45	$ 1,650.029	$ 1,589.942	$ 1,294.318	$ 888.944	$ 544.422	$ 359.904	$ 306.536	$ 313.849	$ 375.153	$ 599.012	$ 1,082.085	$ 1,458.276
G-43/46	$ 9,250.482	$ 8,733.736	$ 7,273.082	$ 5,169.975	$ 2,094.582	$ 1,530.720	$ 1,378.810	$ 1,447.077	$ 1,552.938	$ 2,165.354	$ 6,102.177	$ 7,962.143
G-51/55	$ 139.981	$ 137.061	$ 127.148	$ 115.972	$ 108.676	$ 102.744	$ 98.539	$ 102.119	$ 102.993	$ 106.634	$ 120.316	$ 132.149
G-52/56	$ 762.870	$ 737.308	$ 675.111	$ 597.019	$ 419.373	$ 394.261	$ 384.498	$ 395.340	$ 402.564	$ 428.926	$ 635.414	$ 697.763
G-53/57	$ 7,043.615	$ 6,440.177	$ 5,969.820	$ 5,063.387	$ 2,658.873	$ 2,447.898	$ 2,467.245	$ 2,616.288	$ 2,501.361	$ 2,794.007	$ 5,554.697	$ 6,289.078
G-54/58	$ 3,858.384	$ 3,871.702	$ 3,511.446	$ 3,977.013	$ 2,911.483	$ 3,019.472	$ 3,121.818	$ 3,251.743	$ 3,142.690	$ 3,126.025	$ 4,823.736	$ 3,959.866

Attachment 7 : Data for DOE Table 1 Calculation (Page 2)

		Monthly Revenue Per Customer for Calculating Revenue Decoupling Adjustment. Total RPC (sum of Permanent Rates RPC and STEP adjustment RPC).											
Rate Class	Annual Allowed (Target) RPC	January	February	March	April	May	June	July	August	September	October	November	December
R-1/5	$277	$ 27.50	$ 26.94	$ 25.57	$ 23.60	$ 21.70	$ 20.32	$ 19.40	$ 19.48	$ 19.97	$ 21.31	$ 24.18	$ 26.83
R-3/6	$657	$ 102.12	$ 97.75	$ 78.29	$ 52.75	$ 35.21	$ 26.06	$ 23.41	$ 23.55	$ 25.98	$ 38.43	$ 65.22	$ 88.27
R-4/7	$657	$ 102.12	$ 97.75	$ 78.29	$ 52.75	$ 35.21	$ 26.06	$ 23.41	$ 23.55	$ 25.98	$ 38.43	$ 65.22	$ 88.27
G-41/44	$1,661	$ 246.33	$ 236.53	$ 192.38	$ 133.52	$ 92.65	$ 73.62	$ 68.95	$ 69.26	$ 74.03	$ 98.78	$ 161.73	$ 213.61
G-42/45	$10,462	$ 1,650.03	$ 1,589.94	$ 1,294.32	$ 888.94	$ 544.42	$ 359.90	$ 306.54	$ 313.85	$ 375.15	$ 599.01	$ 1,082.09	$ 1,458.28
G-43/46	$54,661	$ 9,250.48	$ 8,733.74	$ 7,273.08	$ 5,169.98	$ 2,094.58	$ 1,530.72	$ 1,378.81	$ 1,447.08	$ 1,552.94	$ 2,165.35	$ 6,102.18	$ 7,962.14
G-51/55	$1,394	$ 139.98	$ 137.06	$ 127.15	$ 115.97	$ 108.68	$ 102.74	$ 98.54	$ 102.12	$ 102.99	$ 106.63	$ 120.32	$ 132.15
G-52/56	$6,530	$ 762.87	$ 737.31	$ 675.11	$ 597.02	$ 419.37	$ 394.26	$ 384.50	$ 395.34	$ 402.56	$ 428.93	$ 635.41	$ 697.76
G-53/57	$51,846	$ 7,043.62	$ 6,440.18	$ 5,969.82	$ 5,063.39	$ 2,658.87	$ 2,447.90	$ 2,467.25	$ 2,616.29	$ 2,501.36	$ 2,794.01	$ 5,554.70	$ 6,289.08
G-54/58	$42,575	$ 3,858.38	$ 3,871.70	$ 3,511.45	$ 3,977.01	$ 2,911.48	$ 3,019.47	$ 3,121.82	$ 3,251.74	$ 3,142.69	$ 3,126.03	$ 4,823.74	$ 3,959.87

Source: DG 20-105, Exhibit 49, Bates 036 (Settlement Agreement)

G-42 to G-43	$44,199
Customers (Eq Bills)	12
Allowed Revenue chang	$530,388.00
Actual Revenue change	-22
Net to RDAF	$530,410.00



000051

MEMORANDUM

TO:	**Peter Dawes**, Vice President, Finance and Administration Energy North Natural Gas ("ENNG" or the "Company") d/b/a Liberty Utilities
FROM:	**Gregg Therrien** Concentric Energy Advisors, Inc. ("Concentric" or "CEA")
CC:	**Steve Mullen** (ENNG), **James Bonner** (ENNG), **Chris Wall** (CEA), **Peter Hoegler** (CEA)
DATE:	August 8, 2019
RE:	**Review of ENNG's Revenue Decoupling Mechanism**

SECTION I. EXECUTIVE SUMMARY

ENNG has engaged Concentric to conduct an audit of its recently approved revenue decoupling mechanism ("RDM") because the actual RDM results to date have resulted in distribution revenues $1.4 million[1] below that allowed in the Company's last rate case.[2] Additionally, the RDM calculation has shown volatile results and has produced an unanticipated large credit to customers over the first seven months since the RDM has been in place.

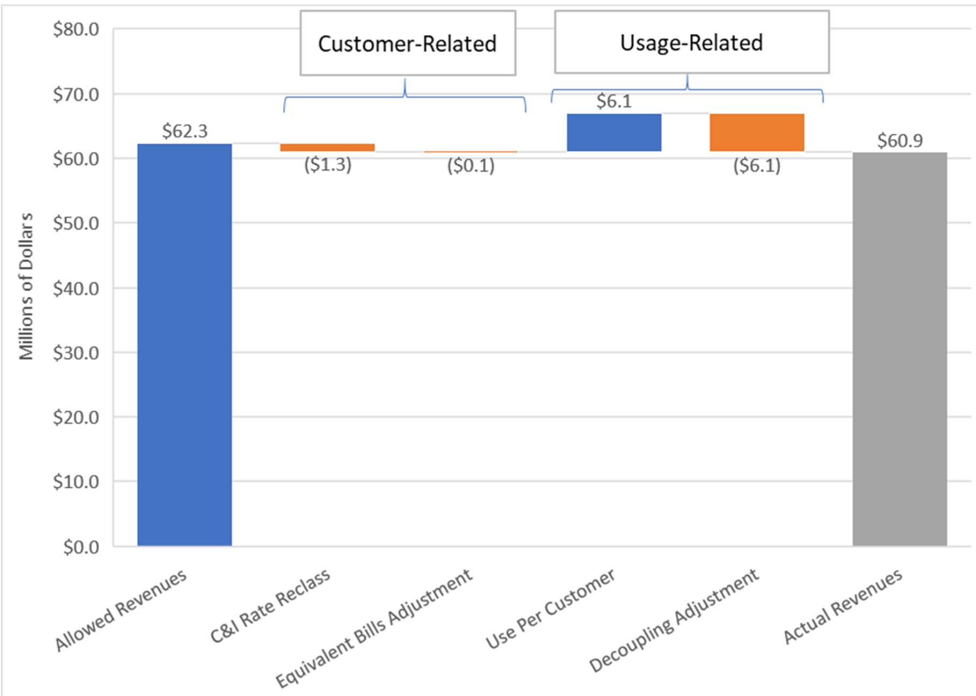
Concentric's findings are summarized as follows:

i. *The Company's RDM calculations are accurate.*
ii. *Actual class-level customer counts are significantly different than approved customer levels, resulting in a $1.4 million distribution revenue shortfall because:*
    a. *A Post-Test Year C&I customer reclass was not reflected in the rate case, and*
    b. *The New Hampshire Public Utilities Commission ("NHPUC") Staff made an "equivalent bills" adjustment in the rate case that makes attaining allowed revenues difficult.*
iii. *Increased use per customer is driving the large RDM credit.*
iv. *ENNG's use per customer trends are consistent with other regional natural gas companies.*
v. *The real-time weather normalization adjustment ("WNA") is now functioning properly after a $0.264 million error was discovered in November 2018 and subsequently credited back to customers in April 2019.*
vi. *The Company's unbilled revenue methodology is prone to higher monthly variation than other methods. Two minor errors in the seven months of entries also contributed to monthly decoupling entry variances.*

[1] For the period of November 2018 through May 2019.
[2] Docket No. 17-048 "Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities Distribution Service Rate Case", Final Decision dated April 27, 2018 (the "Final Decision").

The following chart summarizes the components of the variance between allowed and actual distribution revenues:

Chart 1: Components of Distribution Revenue Variance



The purpose of an RDM is to sever the link between sales units (usage) and revenues, thus enabling companies to freely promote conservation measures to their customers without suffering financial harm. A revenue per customer ("RPC") RDM construct is intended to recognize that adding new customers requires compensation to fund the incremental investment necessary to connect that customer to the distribution system. As such, an RPC RDM does not reconcile differences in customer counts.

The above chart shows that changes in customers compared to the approved rate year has resulted in an unfavorable margin variance of $1.4 million. This is primarily the result of two factors: 1) a February 2018 commercial and industrial ("C&I") rate review, which resulted in a significant reclassification of customers among the C&I rate schedules, and 2) a late adjustment to target (allowed) distribution revenues and customer counts ("equivalent bills") by the NHPUC Staff at the end of the rate case proceeding.

The $6.1 million favorable margin variance related to higher use per customer is properly captured through the RDM and nets to zero.

SECTION II. BACKGROUND

ENNG has engaged Concentric to conduct an audit of its recently approved RDM because the actual RDM results to date have resulted in distribution revenues $1.4 million below that allowed in the Company's last rate case. Additionally, the RDM calculation has shown volatile results and has produced an unanticipated large credit to customers over the first seven months since the RDM has been in place. The large RDM credit is unanticipated because the "real time" WNA is billed monthly on each customer's bill, thereby eliminating the largest anticipated variance component of the RDM, weather. Concentric first produced a work plan to address the primary purpose of this engagement, which is to determine whether there are any structural deficiencies in the RDM construct.

The details of this work plan consist of the following:

1. *Verify that the RDM is functioning properly, through investigation of the following:*
    i. *That the Allowed Revenue Per Customer being used in the RDM calculation is accurate and consistent with the approved billing determinants and allowed revenues from the rate case;*
    ii. *That the Actual Revenue Per Customer ("RPC") since inception of the RDM is also calculated correctly, and*
    iii. *That Concentric's independently calculated monthly RDM variances are equal to that recorded by the Company.*
2. *Quantify the monthly variances by category (i.e., customer-related and usage related);*
3. *Calculate the monthly weather-related variance and compare that result to actual billed WNA revenues;*
4. *Validate the monthly unbilled entries, and quantify the unbilled contribution to monthly variances, and*
5. *Summarize our audit findings and provide Concentric's recommendations.*

SECTION III. THE ENNG VARIANCE ANALYSIS

The Company provided Concentric with its monthly decoupling values as well as its variances to allowed distribution revenues. This is summarized as follows:

Table 1: Variance to Allowed Distribution Revenues (November 2018 – May 2019)

Line	Revenue Type	Total
1	Allowed Distribution Revenues	62,292,497
2	Actual Distribution Revenues	60,930,806
3	Difference	(1,361,691)
4	Decoupling Deferral[1]	(6,089,952)

1 Included in Line 2 above.

As Table 1 indicates, cumulative actual revenues (inclusive of the decoupling adjustment) are below allowed by $1.4 million. This significant unfavorable variance, coupled with the larger than anticipated decoupling adjustment, led to this audit to ensure the RDM is functioning properly and that the base revenue target RPC is appropriate and calculated consistent with the Final Decision.

SECTION IV. PRELIMINARY RESULTS

On July 12, 2019 Concentric reviewed a Microsoft PowerPoint© presentation with ENNG Management. This presentation included the following preliminary findings:

- The Company's RDM calculations are accurate.
    - Target RPC, by class and in total, are calculated correctly;
    - Actual Calendar Revenues cannot be calculated on a Class RPC basis because of the system-wide unbilled methodology, and
    - The method used to calculate the decoupling adjustment is different than the approved tariff methodology, but mathematically should yield the same result.
- Actual customer counts are below Allowed levels, primarily in the Commercial and Industrial ("C&I") rate classes result in a $0.7 million[3] delivery revenue shortfall that is not recoverable through decoupling.
- Use Per Customer Growth drives the higher than anticipated decoupling credits.
- The unbilled calculation contributes significantly to the monthly variances, making it difficult to assess the true impact of the decoupling adjustment.

As a result of this presentation Concentric was asked to further investigate use per customer trends from other New England gas companies. The above findings have been validated and refined, and now also include the requested use per customer comparisons.

SECTION V. FINAL FINDINGS

A. The Company's RDM calculations are accurate.

Concentric validated the Company's monthly RDM calculations by performing three tests:

1. *Replicate the monthly Target RPC;*
2. *Validate the Company's monthly Actual RPC, and*
3. *Compare the differences from steps 1 and 2 to the Company's reported monthly decoupling amounts.*

These steps require a review of the Company's unbilled methodology and monthly entries, which are necessary to report monthly revenues on a calendar basis.

The first audit test was to validate that the monthly RPC targets were calculated correctly using class-specific data from the Final Decision. CEA first obtained the final approved billing determinants from the Final Decision, which includes the number of customers (equivalent bills), throughput (therms), and the appropriate tariff's monthly fixed charges and delivery rates per therm. We then multiplied these billing determinants by the tariff rates to derive monthly allowed distribution revenues by rate class. Each class-specific distribution revenue was then divided by the allowed number of equivalent bills to derive class-

[3] Concentric's preliminary finding used customer rates to quantify the customer variance. The final analysis contained in this memorandum properly uses the class RPC values, which are used in the RDM calculation.

specific revenue per customer targets. Lastly, these revenue per customer targets were compared to the Company's RDM calculation workbook and were found to tie out in each class for each month.

The second step was to validate the Company's Actual RPC calculations. This was performed in total rather than at the class level because of the nature of the unbilled calculation (discussed below in Section VII). Unbilled is calculated by first using actual system gate station receipts less company use, daily metered volumes[4] and a lost-and-unaccounted-for deduction[5] pertaining to local delivery system losses. Because the Company utilizes the "gate station approach" to estimate unbilled sales, class-level detail is not possible. Therefore, Concentric reviewed both the class-specific billed revenues, the unbilled revenue estimate and the calculation of monthly equivalent bills to validate the monthly Actual revenues.

Concentric's review of the underlying billing data and unbilled entries did uncover a minor unbilled estimation error whereby the number of equivalent bills used in the unbilled calculation were incorrect for the months of November 2018 through and including March 2019[6]. This error has no effect on the seven-month cumulative variance, as the unbilled accruals are reversed each month and the equivalent bills error was corrected in the April 2019 accrual. Concentric then performed a second reasonableness test whereby the unbilled sales volumes and equivalent bills were spread to the rate classes based on billed volume percentages. This provided a "sanity check" calculation, which showed material volatility in the C&I classes. The root cause of this volatility is discussed below.

The third step compares the actual RPC to the Allowed RPC and multiplied times the number of calendar month equivalent bills. This calculation yielded a decoupling value very close to the Company's recorded decoupling revenues in total, but significant monthly variances in the months of November 2018 through March 2019.

A. Customer counts are significantly different than that allowed in the rate case.

Average customers for the period of November 2018 through May 2018 were compared to the 2016 rate year for each rate class. The variance in customer counts was then multiplied times the Allowed RPC for the same period. This calculation is shown below:

[4] Daily metered volumes are excluded from the unbilled calculation as they are billed on a true calendar basis.

[5] The Company utilizes a 1.6% lost-and-unaccounted-for percentage in all months. No attempts were made by Concentric to validate this assumption.

[6] Actual cycle-based number of bills was inadvertently used in these five months.

Table 2: Distribution Revenue Impact Related to Average Customer Counts

	Average Customer Counts			Distribution Revenue	
Rate Class	**Actual**	**Rate Year**	**Actual Versus Rate Year**	**Allowed RPC 11/2018 through 5/2019**	**Rate Year Variance**
R-1	3,133	3,558	(425)	$167	($70,804)
R-3	72,472	72,142	330	$458	$151,279
R-4	5,906	5,315	592	$177	$104,676
R-5	64	-	64	$217	$13,882
R-6	185	-	185	$596	$110,225
R-7	3	-	3	$230	$707
Total Residential	**81,763**	**81,015**	**749**		**$309,964**
G-41	9,200	9,147	53	$1,117	$58,864
G-42	1,379	1,755	(376)	$6,515	($2,448,421)
G-43	58	48	10	$43,278	$432,051
G-44	2	-	2	$1,452	$2,317
G-45	4	-	4	$8,469	$36,216
G-46	-	-	-	$56,262	$0
G-51	1,227	1,360	(133)	$810	($107,489)
G-52	374	325	49	$4,085	$199,787
G-53	36	32	4	$34,929	$151,109
G-54	28	26	2	$25,621	$52,094
G-55	3	-	3	$1,053	$2,909
G-56	-	-	-	$5,311	$0
G-57	-	-	-	$45,408	$0
G-58	1	-	1	$33,307	$36,320
Total C&I	**3,109**	**3,546**	**(437)**		**($1,682,336)**
Total All	**84,872**	**84,561**	**311**		**($1,372,372)**

As the above table indicates, the total difference in customer counts is the source of the difference between Actual and Allowed distribution revenues.

a. A Post-Test Year C&I Customer Reclass was not Included in the Decoupling Targets.

In February 2018 the Company analyzed its C&I rate classes to determine if any customers were not properly assigned to the appropriate rate class. For example, if a commercial customer has been receiving service under Rate G-41 (with an availability requirement that the customer must use less than 10,000 therms annually and use more than 67% of its annual usage in the winter months) and, as a result of the annual rate review it is determined that the customer has increased its annual usage above 10,000 therms, the customer is then reclassified to the G-42 rate schedule.

Concentric's review of current customer counts compared to that imputed into allowed revenues showed significant variation, particularly in the C&I class. We determined that the C&I rate review conducted in February 2017 was not accounted for in the rate case. The summary of these customer reclasses is as follows:

Table 3: February 2017 C&I Rate Reclassifications

Rate Class	C&I Customer Reclass				
	Out	In	Net	11/2018 - 5/2019 Allowed RPC	Delivery Revenue Impact
G-41	(489)	789	300	$1,117	$335,148
G-42	(529)	241	(288)	$6,515	($1,876,269)
G-43	(18)	17	(1)	$43,278	($43,278)
G-51	(437)	358	(79)	$810	($64,015)
G-52	(97)	162	65	$4,085	$265,532
G-53	(10)	15	5	$34,929	$174,647
G-54	(9)	7	(2)	$25,621	($51,241)
Total	**(1,589)**	**1,589**	**-**		**($1,259,476)**

This variance is a subset of the total customer-related margin variance calculated in Table 2.

b. Test Year Adjustments Included in the Decoupling Targets Makes Attaining Imputed Customer Counts Difficult.

Near the completion of the litigated rate case in Docket No. 17-048 the Commission Staff required the Company to make a calendarization adjustment for the number of test year bills. This adjustment is intended to "normalize" the test year customer counts and reflect new customer accounts added during the test year. The Company's approach to this request was to calculate an equivalent bills adjustment, which both smoothed test year customer counts and recognized new customer additions made during the test year. This adjustment resulted in the following increase to Allowed customer counts, therms and revenues:

Table 4: Rate Year Equivalent Bills Adjustment

Rate Class	Annual Bills	Annual Therms	Delivery Revenues
R-1	386	7,154	$8,475
R-3	14,336	1,043,363	$789,374
R-4	(1,580)	(214,472)	($56,689)
Total Residential	**13,142**	**836,045**	**$741,160**
G-41	3,214	485,913	$342,087
G-42	343	561,680	$238,682
G-43	(28)	(554,018)	($138,357)
G-51	99	14,201	$8,535
G-52	79	155,599	$40,388
G-53	(21)	(544,071)	($96,774)
G-54	(16)	(836,835)	($47,439)
Total C/I	**3,670**	**(717,529)**	**$347,123**
Total All	**16,812**	**118,516**	**$1,088,283**

The above adjustment is included in the Approved RPC targets resulting in a higher customer count that must be attained to achieve allowed delivery revenues. The RDM adjustment does not compensate the Company for lower actual customer counts than that imputed into base delivery revenues. The RDM is designed to sever the link between sales (therms) and revenues, not customer counts.

B. Use Per Customer

Again, the purpose of the RDM is to sever the link between customer usage and delivery revenues. Reasons for usage variances are primarily the result of colder or warmer than normal weather, conservation measures (from both ratepayer-funded programs and individual customer conservation measures) and economic activity. Given the Company's RDM construct that includes a real-time WNA, the variances related to use per customer were anticipated to be small. To the contrary, the decoupling revenue adjustment has credited customers $6.1 million over the first seven months of operation. The real-time WNA has properly captured the weather-related variance (discussed in Section VI below), which leaves the entire RDM adjustment attributable to use per customer. The increase in use per customer has occurred in both the Residential and C&I sectors:

Chart 2: Residential Use Per Customer

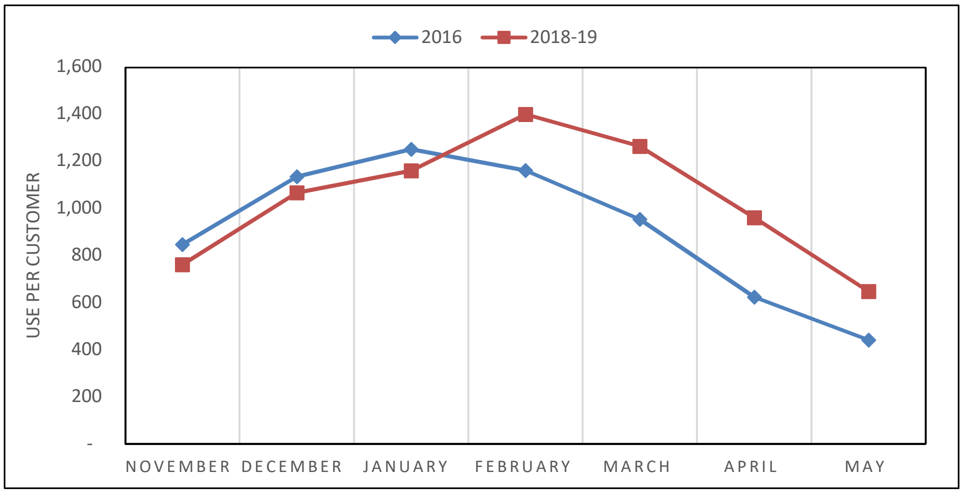
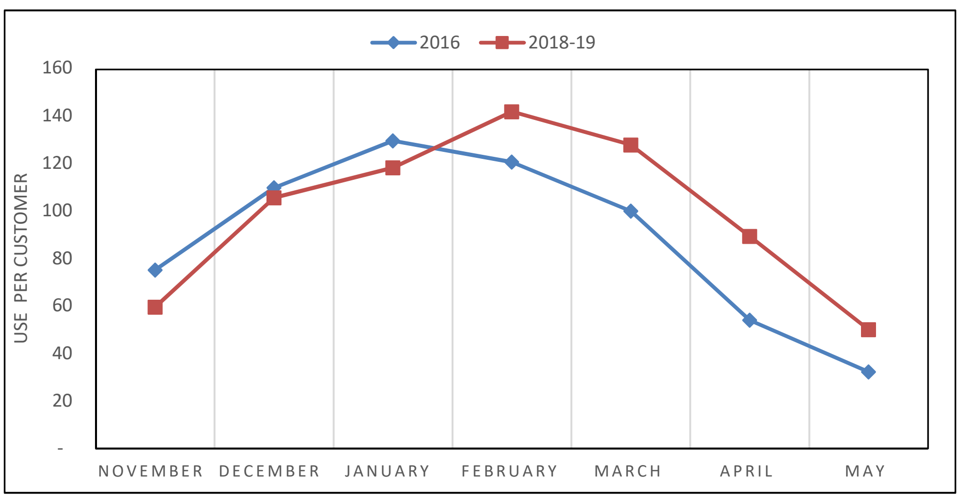


Chart 3: C&I Use Per Customer



At the preliminary findings presentation, the Company was surprised by the recent increase in UPC, particularly for the Residential class. Concentric was asked to compare ENNG's UPC to that of neighboring natural gas utilities. Concentric was able to obtain customer and usage data from the following companies[7]:

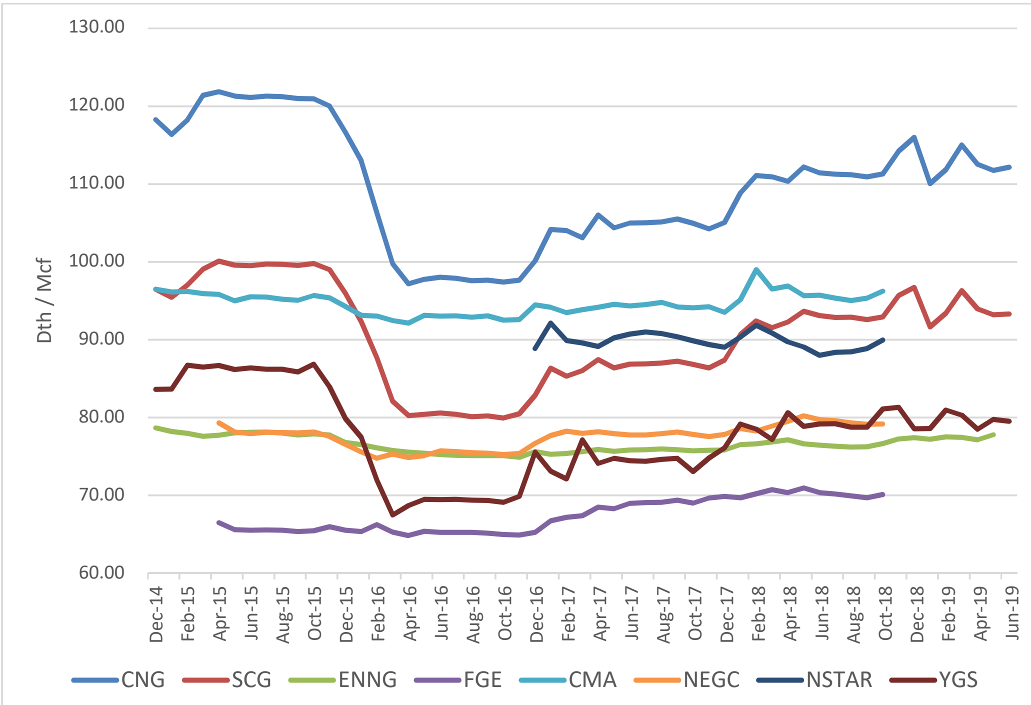
[7] This portion of the memorandum will be shared with the list of participants in recognition of their voluntary involvement in the study.

Table 7: Participating Local Gas Distribution Companies ("LDCs")

Utility	Abbreviation	Location	Approximate Number of Customers
Connecticut Natural Gas	CNG	Greater Hartford, CT and Greenwich, CT	180,000
Columbia Gas – MA	CMA	Springfield and Laurence, MA	325,000
Eversource Gas – MA	NSTAR	Central MA	290,000
Liberty – NH	ENNG	New Hampshire	95,000
National Grid – RI	NEGC	Rhode Island	55,000
The Southern Connecticut Gas Company	SCG	Greater New Haven and Bridgeport, CT	200,000
Unitil – MA	FGE	Fitchburg, MA	16,000
Eversource – CT	YGS	Across CT	200,000

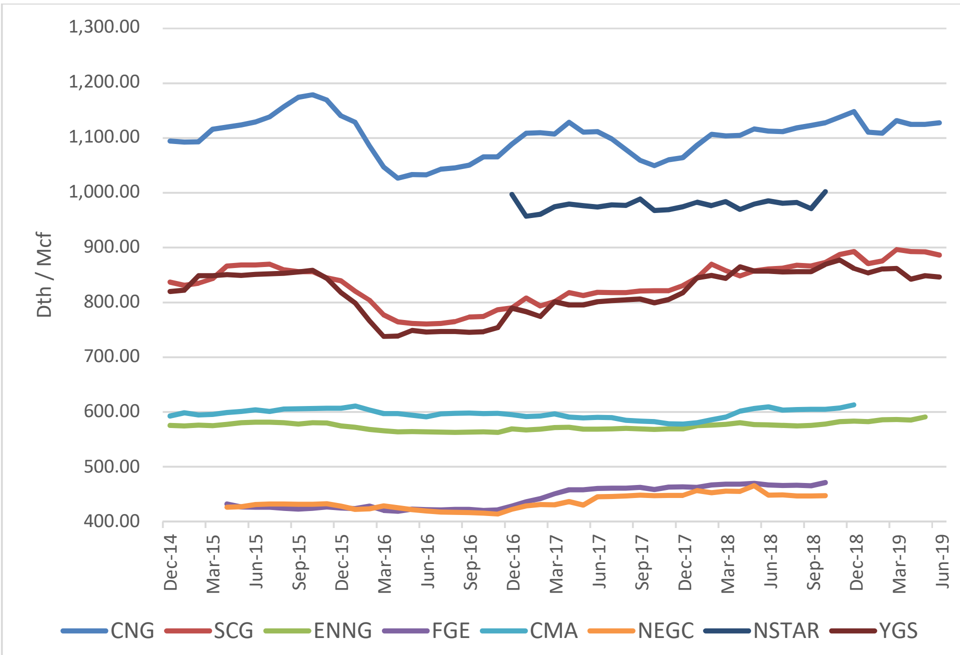
Monthly customer and usage data was obtained by rate class for as far back as January 2014. Concentric then calculated monthly UPC, then calculated a 12-month rolling total. Normalized consumption data was used where available. The data below represents summarized data for Residential (heat and non-heat), Commercial and Industrial customer classes.

Chart 4: Residential Use Per Customer Trends: 12-Month Rolling Total



The CNG, SCG and YGS trend lines are difficult to compare because only actual usage data was provided while all other survey respondents included both actual and normalized volumes. Still, the trend over the most recent three years is consistent with other LDCs.

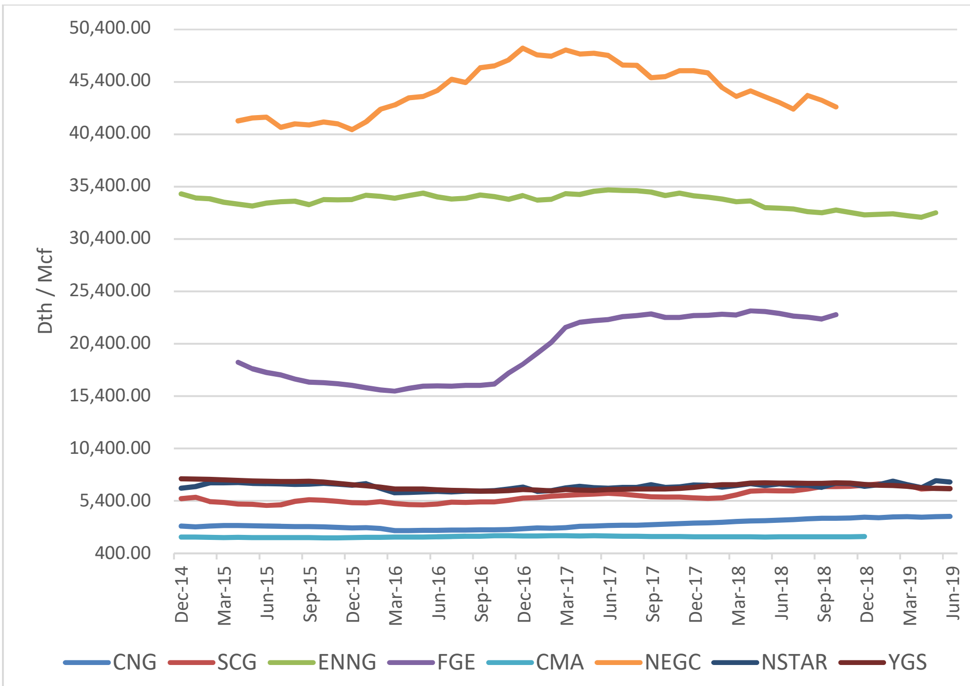
Chart 5: Commercial Use Per Customer[8] Trends: 12-Month Rolling Total



The Commercial trend exhibits a small upward trend for all LDCs except CMA, ENNG and NSTAR.

[8] NSTAR Gas represents a combined C&I UPC.

Chart 6: Industrial Use Per Customer Trends: 12-Month Rolling Total



The industrial class comparison is complicated by the fact that some of the utilities have appreciably different rate designs. For example, CNG, SCG and YGS's Industrial customers are served primarily under Rate LGS – Large General Service. This tariff does not carry a load factor distinction like the other participating LDCs tariffs. As such, the average UPC for these three LDCs appear much lower than those with more granular rate structures.

Appendix A contains individual use per customer graphs for each LDC.

SECTION VI. WEATHER VARIANCES AND THE REAL-TIME WNA

One of the audit tasks is to validate the accuracy of the real-time WNA adjustment. The real-time WNA is a customer-specific calculation that results in either a charge (when weather is warmer than normal) or a credit (when weather is colder than normal). The WNA is billed in the month in which the weather variance occurs, thus matching the charge or credit with the weather-related impact on the bill. Customer WNA billings is captured as a separate revenue component in the Company's revenue reporting, enabling a comparison between what was billed and what a class-level spreadsheet analysis produces. This comparison, although not expected to match perfectly, should indicate that the WNA is functioning properly or not. The results of the comparison between the real-time WNA and the Excel© based weather analysis is as follows:

Table 5: Comparison of Calculated Weather-Related Variance to the Real-Time WNA

Category	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
Distribution Revenues	$6,176,999	$9,601,480	$12,370,924	$12,544,467	$11,461,724	$9,515,278	$6,468,216
Heating Degree Days	*Colder / (Warmer)*						
Actual HDD	601	983	1,085	1,160	1,059	710	415
Normal HDD	504	857	1,162	1,167	1,026	737	414
Difference	97	126	(77)	(8)	33	(27)	1
Variance %	19.3%	14.8%	-6.6%	-0.7%	3.2%	-3.7%	0.3%
Weather Variance	*(Credit) / Charge*						
Calculated WNA	($510,539)	($900,154)	$585,425	$61,848	($255,743)	$218,110	($7,368)
Billed WNA[1]	($65,581)	($926,070)	$568,805	$11,317	($172,550)	$414,250	$206,917
Difference	($444,958)	$25,916	$16,620	$50,531	($83,193)	($196,139)	($214,285)
% of Revenues							
Calculated Weather	-8.3%	-9.4%	4.7%	0.5%	-2.2%	2.3%	-0.1%
Billed WNA	-1.1%	-9.6%	4.6%	0.1%	-1.5%	4.4%	3.2%

Upon reviewing the above comparison, one would expect to see only a small monthly variation between the calculated WNA and the billed WNA. Further, the two methods should move in the same direction (both methods resulting in a credit, or both resulting in a debit). Additionally, the magnitude of the adjustment should reflect the difference in heating degree days ("HDD"). Concentric's findings is that each month from December 2018 through March 2019 appear reasonable, displaying a close correlation between methods.

The months of November 2018 and April 2019 showed material variances between actual billed WNA and the spreadsheet estimate. November has a significant amount of HDDs and the weather was significantly colder than normal (19.3% colder). This colder than normal HDD implies that customers would have their heating systems on for the majority of the month. The fact that the billed WNA was a comparatively small credit compared to the spreadsheet analysis (and weather was significantly colder than normal) indicates that there was likely a billing system issue. It is our understanding from the preliminary results meeting that there was in fact an implementation issue with the real-time WNA in November 2018 and a credit was subsequently applied in April 2019, which explains the variation in these two months.

SECTION VII. THE UNBILLED REVENUE METHODOLOGY AFFECTS THE RDM CALCULATION

Unbilled revenues reflect those sales that occurred in the calendar month but have yet to be billed to the customer. Accounting standards require companies to report revenues on a calendar basis. When companies such as ENNG utilize billing cycles, there is an inevitable mis-match between billed sales (which cross calendar months) and calendar sales. To remedy this mismatch, companies must estimate the value of these unbilled sales. There are three commonly used methods to estimate unbilled sales:

Method 1: Perform a system-wide calculation based on monthly actual gate station take data (the "send-out" method);

Method 2: Utilize a base-thermal methodology, which estimates unbilled revenues based on unbilled heating degree days (the "base-thermal" method), and

Method 3: Utilize actual end-of-month meter reads (the "AMI" method).

Of these three methods, ENNG utilizes method 1. This method is the simplest of the three as it relies on total gate station receipts and system-level adjustments to derive calendar sales. The shortcomings of this method is that results tend to be volatile across the months, and class-level detail is not estimated making variance analysis more difficult. Further, with an RDM that includes rate class revenue targets, performing the monthly RDM entry must be performed at the system level given the current method for unbilled estimation. This means that the Company's actual RDM calculation is different than its published tariff:

Table 6: RDM Methodology Comparison

Approved Tariff Methodology (RPC)	Actual Practice (Revenues)
Step 1: Calculate the difference between Actual RPC and Allowed RPC for each rate class	**Step 1**: Derive Allowed revenues by multiplying the Allowed RPC times the actual number of customers for each rate class and sum them
Step 2: Multiply the RPC differences derived in step 1 times the Actual number of customers in each rate class	**Step 2:** Compare Actual Revenues to Allowed Revenues derived in step 1
Step 3: The sum of the rate class revenue differences calculated in step 2 to derive the monthly decoupling adjustment	**Step 3**: Subtract Actual from Allowed revenues to derive the decoupling adjustment

Both methodologies result in the same decoupling adjustment amount. However, the lack of transparency to the class level for the RDM calculation makes variance analysis more difficult.

There was an error in the unbilled calculation in the months of November 2018 through April 2019. Billing cycle equivalent bills rather than calendar equivalent bills were inadvertently used in the unbilled calculation. This error contributed to significant monthly swings in the RDM revenues, as the mismatch in equivalent bills is captured by the RDM, which includes target RPC based on calendar equivalent bills. The monthly variations are as follows:

Table 7: Unbilled Equivalent Bills Error Impact on Monthly RDM Variation

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
Customer Difference	(3,107)	2,160	3,215	4,977	(4,342)	(99)	(98)
Allowed RPC	$85.90	$112.91	$127.12	$119.83	$102.87	$69.23	$49.68
Dollar Impact	($266,901)	$243,919	$408,697	$596,338	($446,641)	($6,856)	($4,868)
Contribution to Monthly Unbilled Variance	**($266,901)**	**$510,820**	**$164,779**	**$187,641**	**($1,042,979)**	**$439,785**	**$1,988**

Once the error was discovered and corrected in April 2019 the large variation ended.

SECTION VIII. RECOMMENDATIONS

Recommendation 1: Any C&I rate review must be incorporated into the adjusted (rate year) equivalent bills calculation, and do not perform any rate reviews between rate cases.

Recommendation 2: Consider switching to a base-thermal unbilled methodology. This change will require some up-front investment in spreadsheet development but should help smooth monthly variances. This method will enable the Company to calculate its RDM consistent with its approved tariff and help with monthly variance analysis.

Recommendation 3: The real-time WNA should continue to be audited in the Company's billing system, particularly in the months when it is being applied to prorated bills (November and May).

SECTION IX. CONTACT US

Please contact me if there are any questions regarding this memorandum, or if we can provide further assistance.

Regards,

Gregg Therrien
Assistant Vice President
(508) 263-6284

APPENDIX A

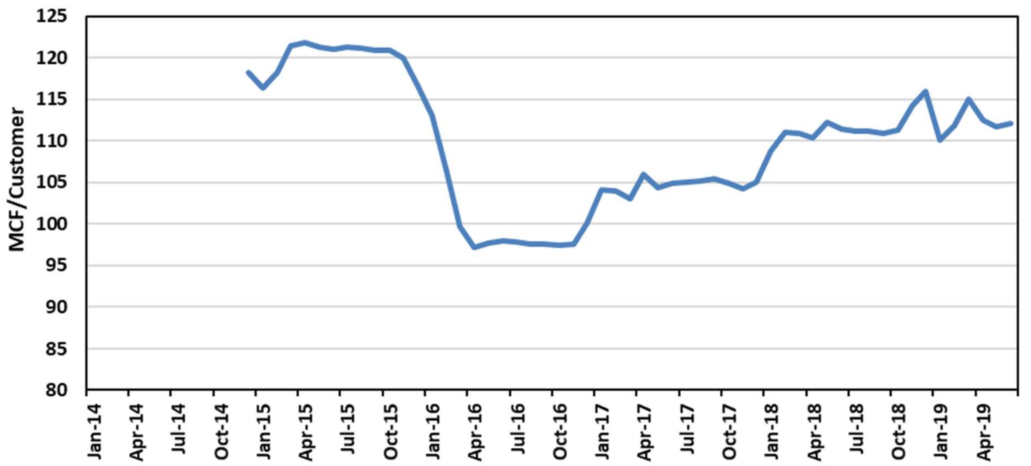
DETAILED USE PER CUSTOMER CHARTS

PARTICIPATING LDCS

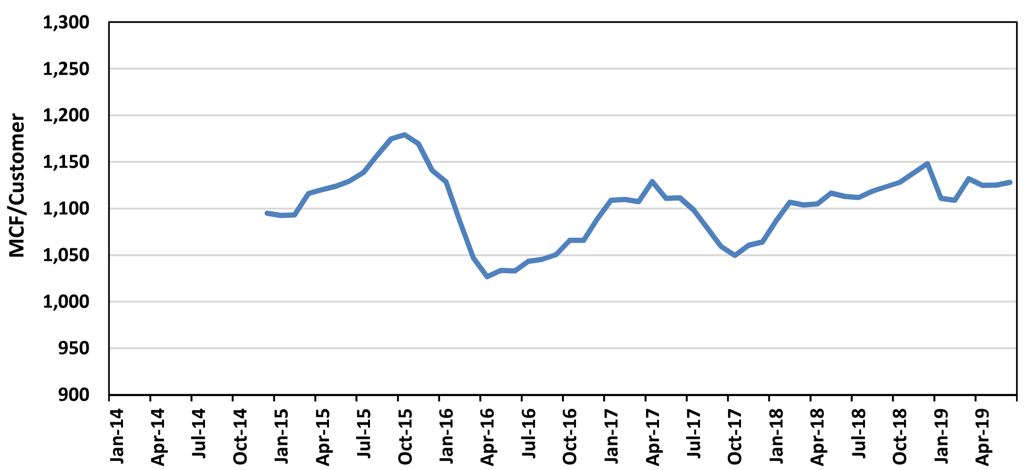
000069

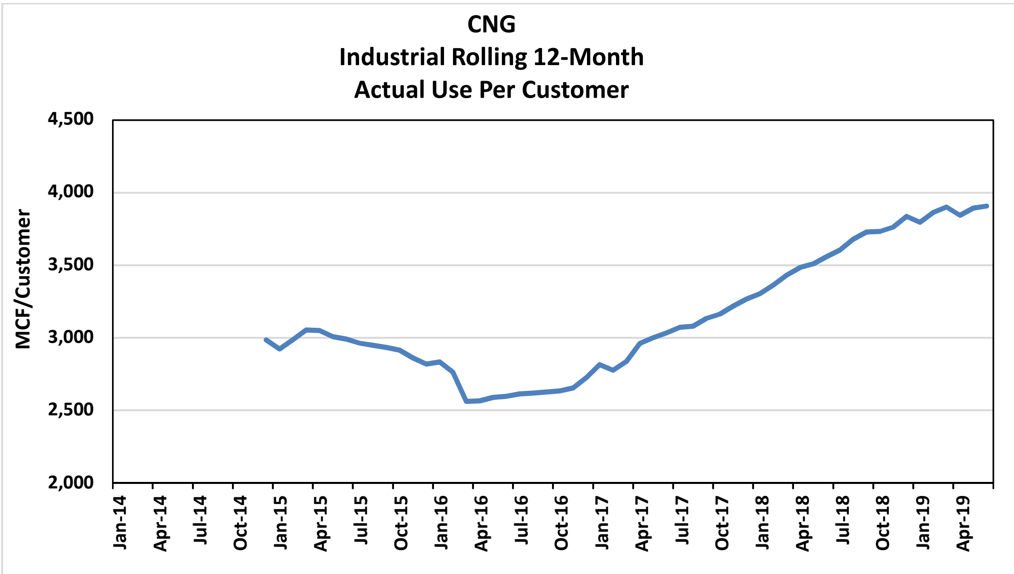
CNG

CNG
Residential Rolling 12-Month
Actual Use Per Customer

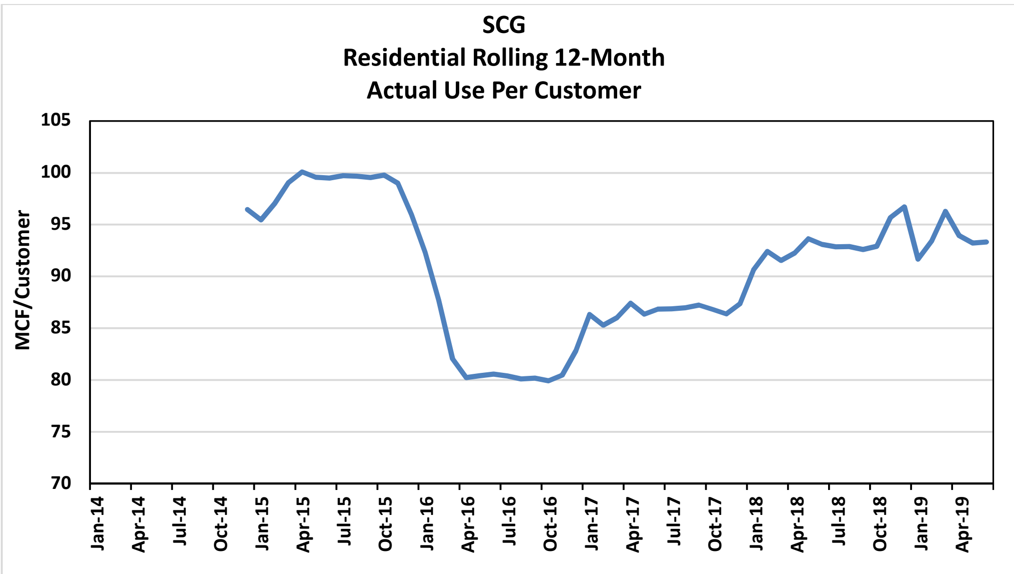


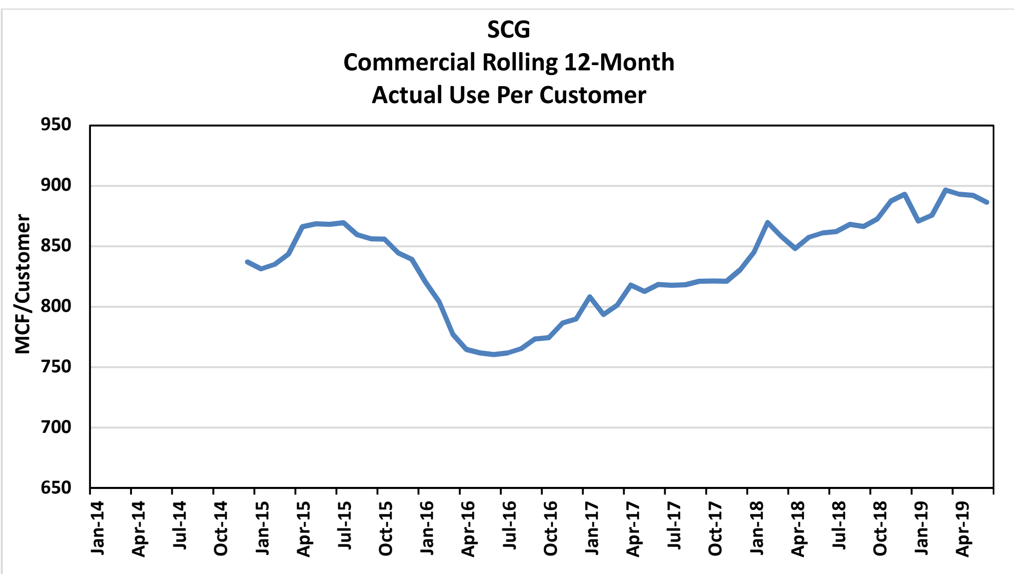
CNG
Commercial Rolling 12-Month
Actual Use Per Customer

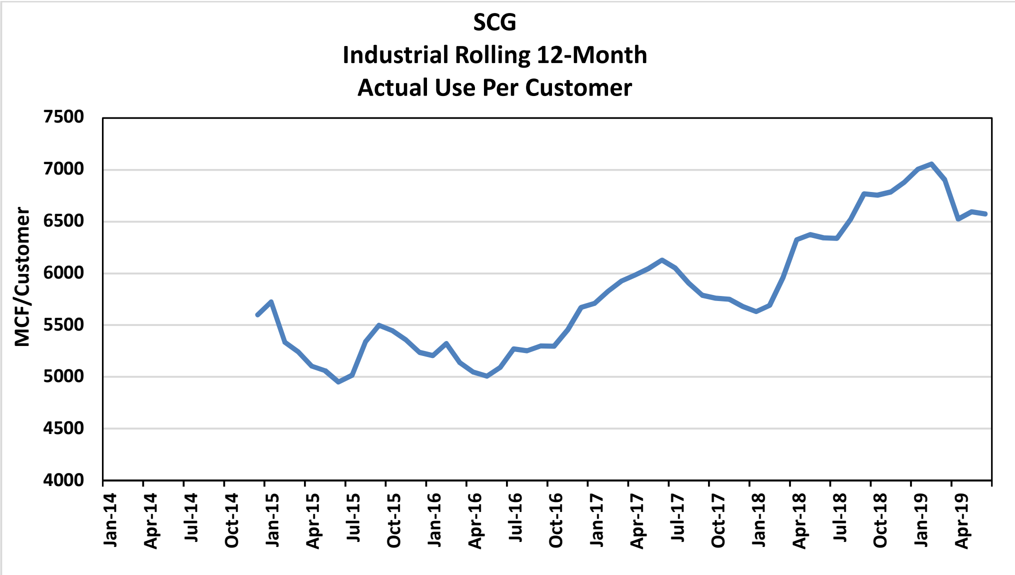



CNG
Industrial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
4,500
4,000
3,500
3,000
2,500
2,000
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
Jul-16
Oct-16
Jan-17
Apr-17
Jul-17
Oct-17
Jan-18
Apr-18
Jul-18
Oct-18
Jan-19
Apr-19

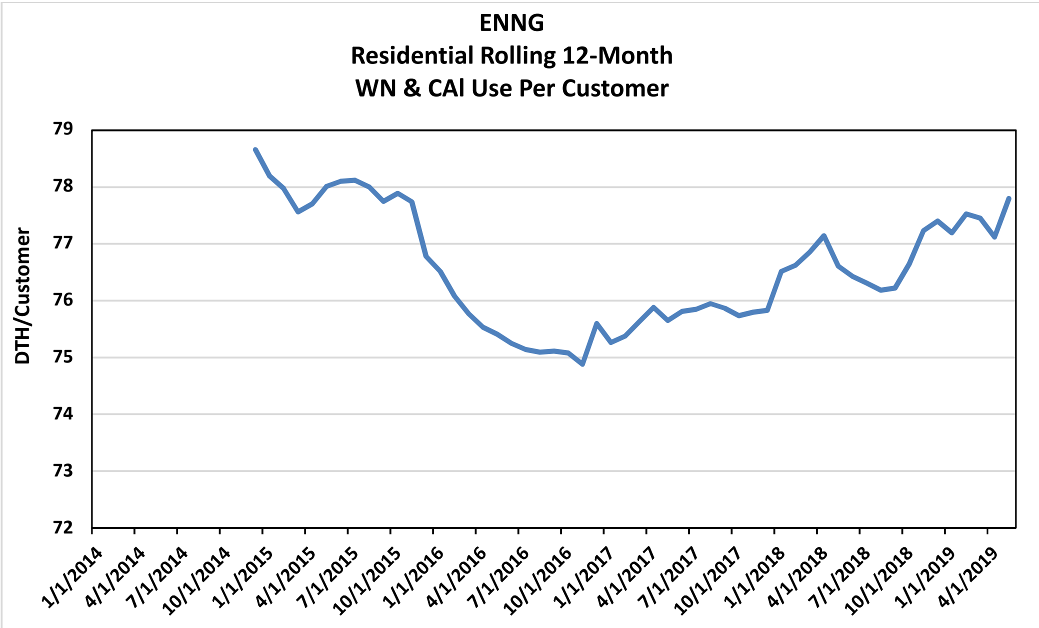
SCG

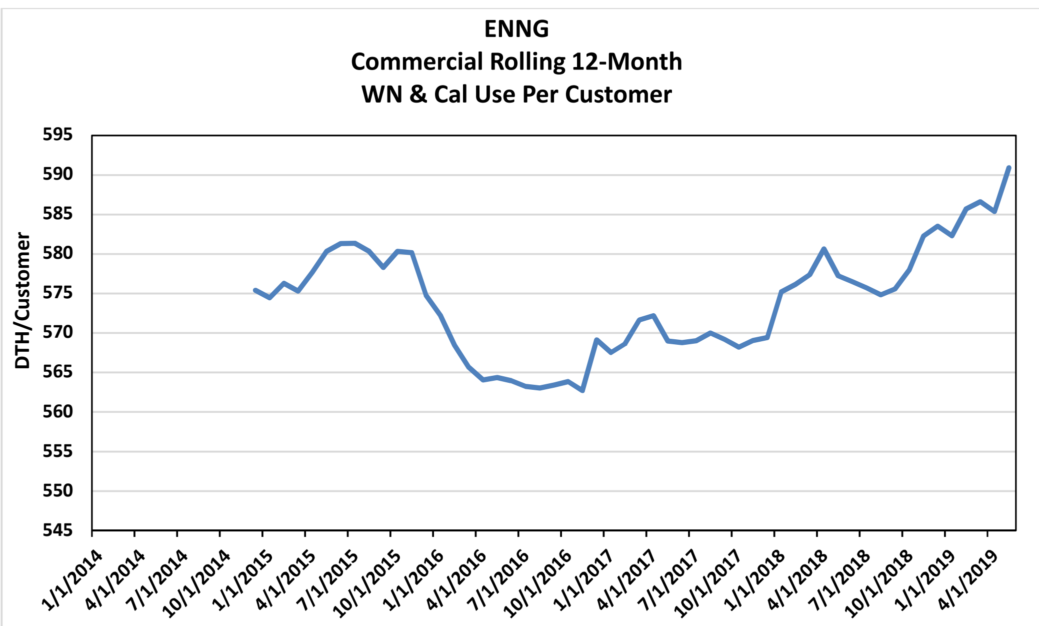

SCG
Residential Rolling 12-Month
Actual Use Per Customer
MCF/Customer
105
100
95
90
85
80
75
70
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
Jul-16
Oct-16
Jan-17
Apr-17
Jul-17
Oct-17
Jan-18
Apr-18
Jul-18
Oct-18
Jan-19
Apr-19

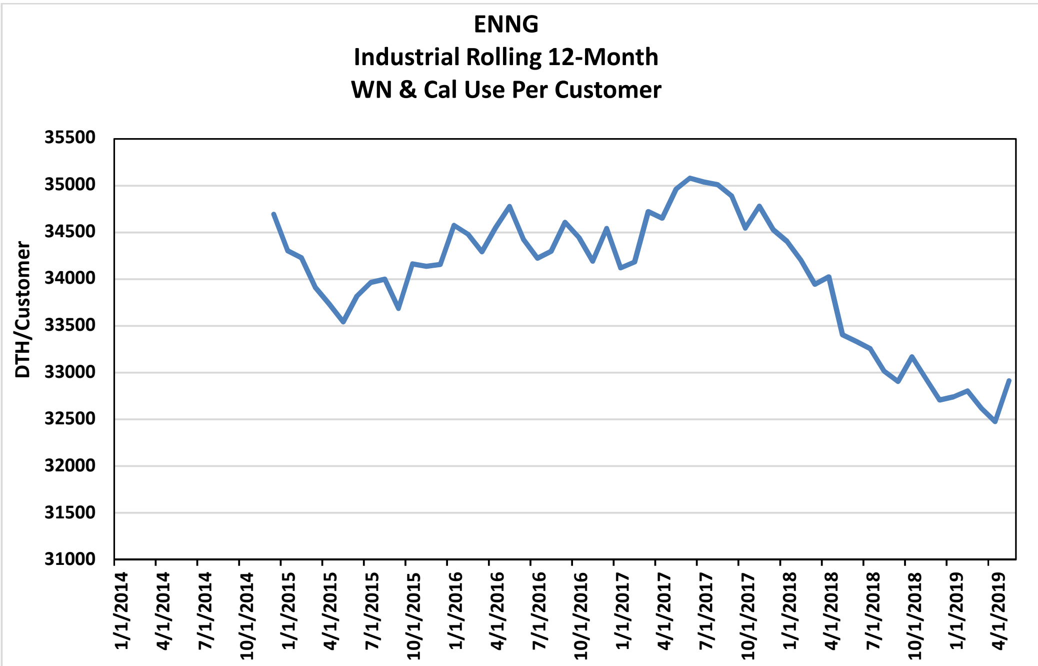

SCG
Commercial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
950
900
850
800
750
700
650
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
Jul-16
Oct-16
Jan-17
Apr-17
Jul-17
Oct-17
Jan-18
Apr-18
Jul-18
Oct-18
Jan-19
Apr-19


SCG
Industrial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
7500
7000
6500
6000
5500
5000
4500
4000
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
Jul-16
Oct-16
Jan-17
Apr-17
Jul-17
Oct-17
Jan-18
Apr-18
Jul-18
Oct-18
Jan-19
Apr-19

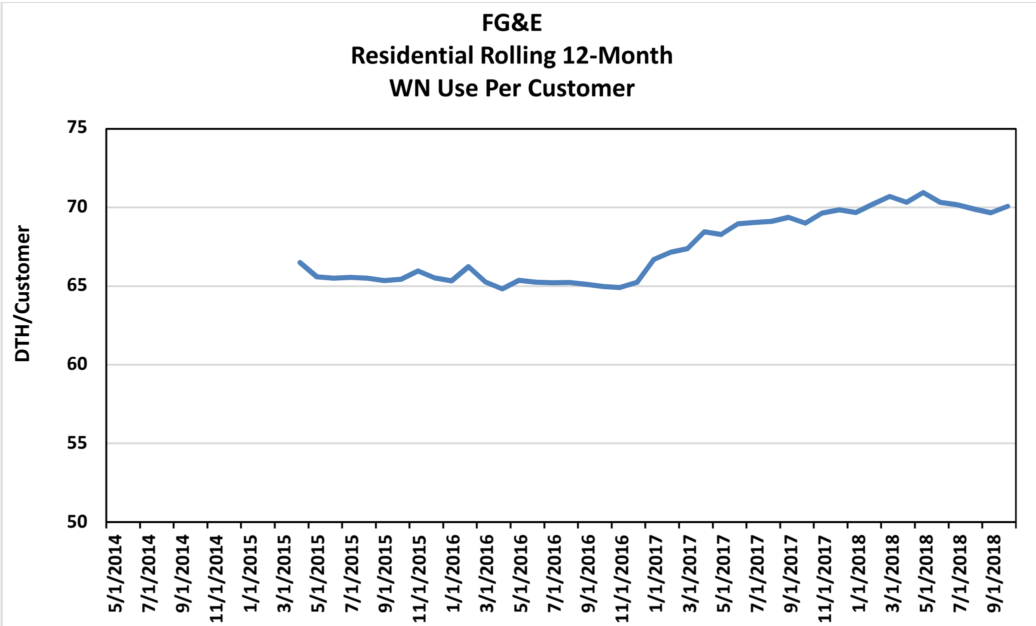
ENNG

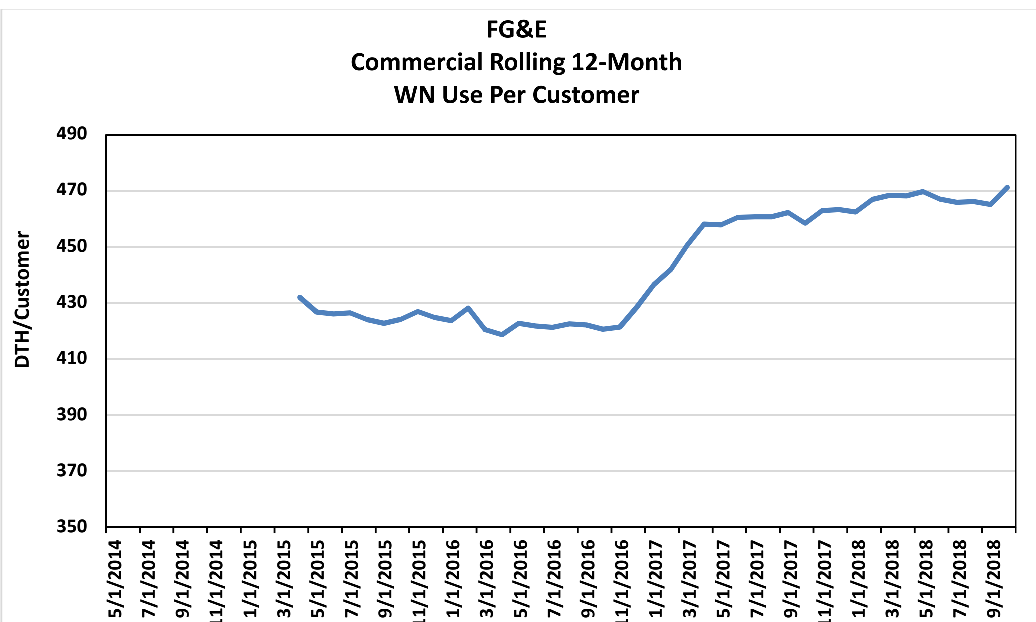

ENNG
Residential Rolling 12-Month
WN & CAl Use Per Customer
DTH/Customer
79
78
77
76
75
74
73
72
1/1/2014
4/1/2014
7/1/2014
10/1/2014
1/1/2015
4/1/2015
7/1/2015
10/1/2015
1/1/2016
4/1/2016
7/1/2016
10/1/2016
1/1/2017
4/1/2017
7/1/2017
10/1/2017
1/1/2018
4/1/2018
7/1/2018
10/1/2018
1/1/2019
4/1/2019

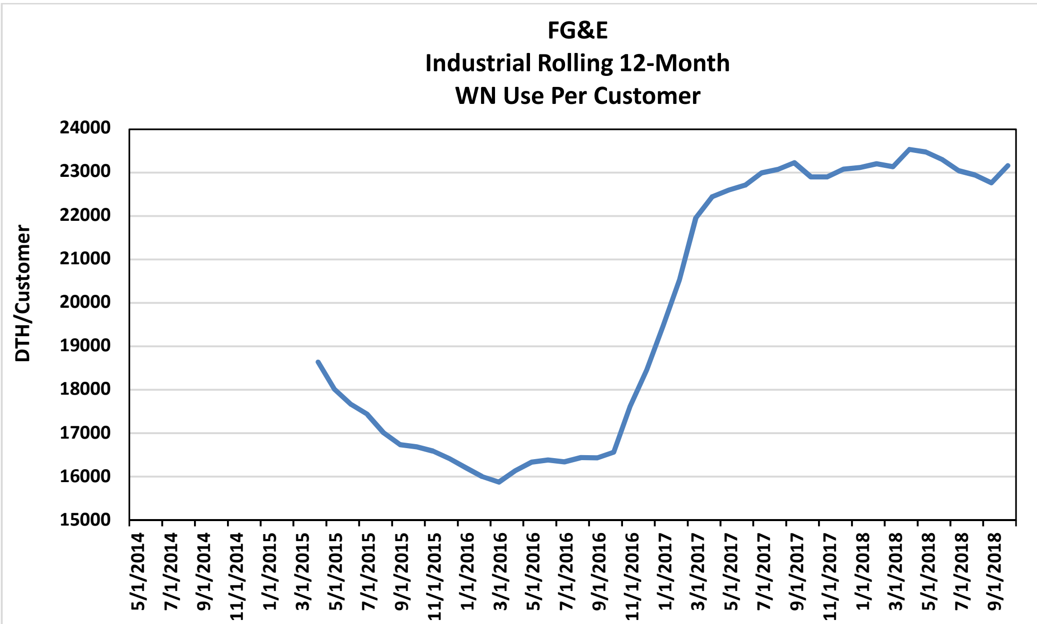

ENNG
Commercial Rolling 12-Month
WN & Cal Use Per Customer
DTH/Customer
595
590
585
580
575
570
565
560
555
550
545
1/1/2014
4/1/2014
7/1/2014
10/1/2014
1/1/2015
4/1/2015
7/1/2015
10/1/2015
1/1/2016
4/1/2016
7/1/2016
10/1/2016
1/1/2017
4/1/2017
7/1/2017
10/1/2017
1/1/2018
4/1/2018
7/1/2018
10/1/2018
1/1/2019
4/1/2019


ENNG
Industrial Rolling 12-Month
WN & Cal Use Per Customer
DTH/Customer
35500
35000
34500
34000
33500
33000
32500
32000
31500
31000
1/1/2014
4/1/2014
7/1/2014
10/1/2014
1/1/2015
4/1/2015
7/1/2015
10/1/2015
1/1/2016
4/1/2016
7/1/2016
10/1/2016
1/1/2017
4/1/2017
7/1/2017
10/1/2017
1/1/2018
4/1/2018
7/1/2018
10/1/2018
1/1/2019
4/1/2019

FGE

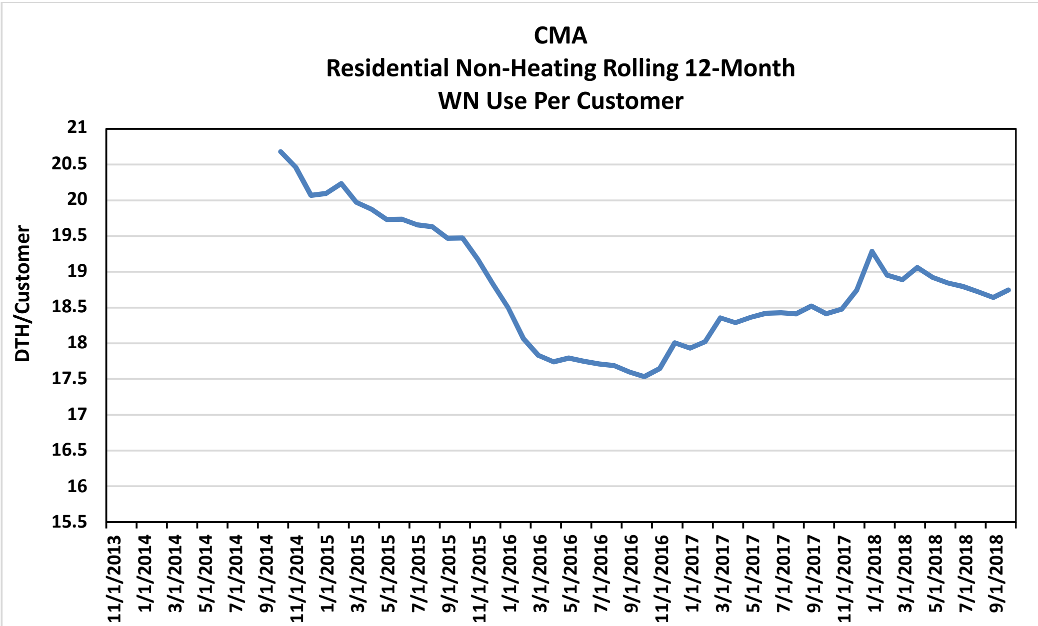

FG&E
Residential Rolling 12-Month
WN Use Per Customer
DTH/Customer
75
70
65
60
55
50
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

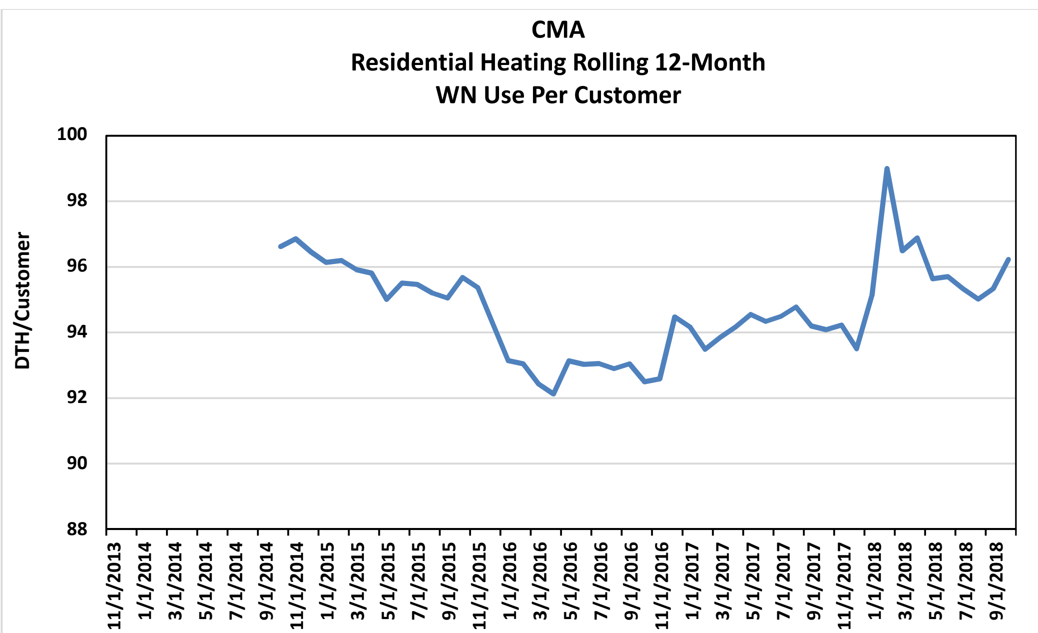

FG&E
Commercial Rolling 12-Month
WN Use Per Customer
DTH/Customer
490
470
450
430
410
390
370
350
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

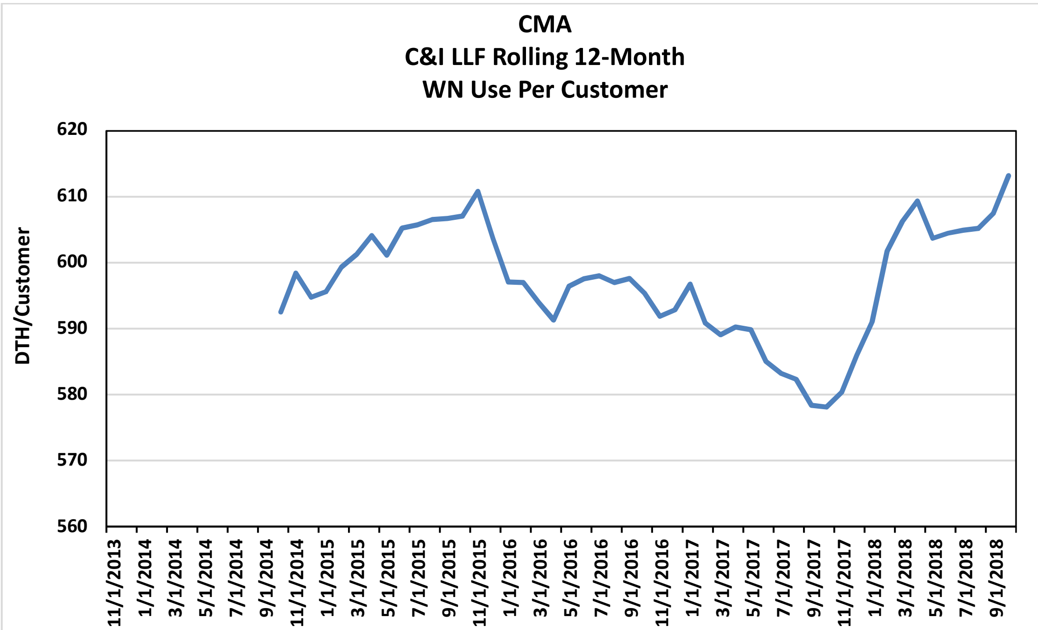

FG&E
Industrial Rolling 12-Month
WN Use Per Customer
DTH/Customer
24000
23000
22000
21000
20000
19000
18000
17000
16000
15000
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

000076

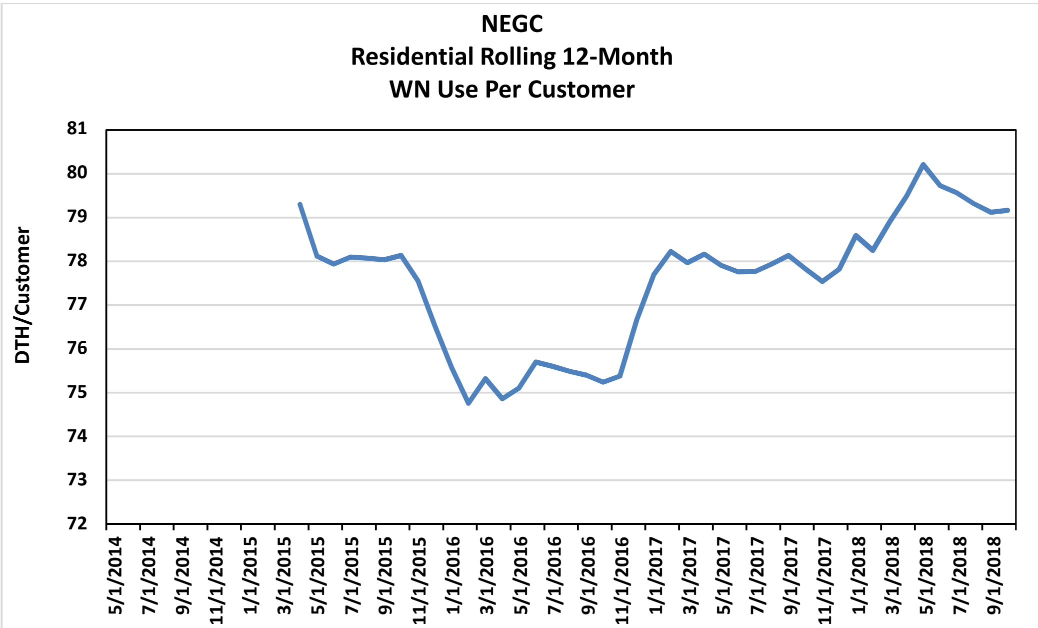
CMA

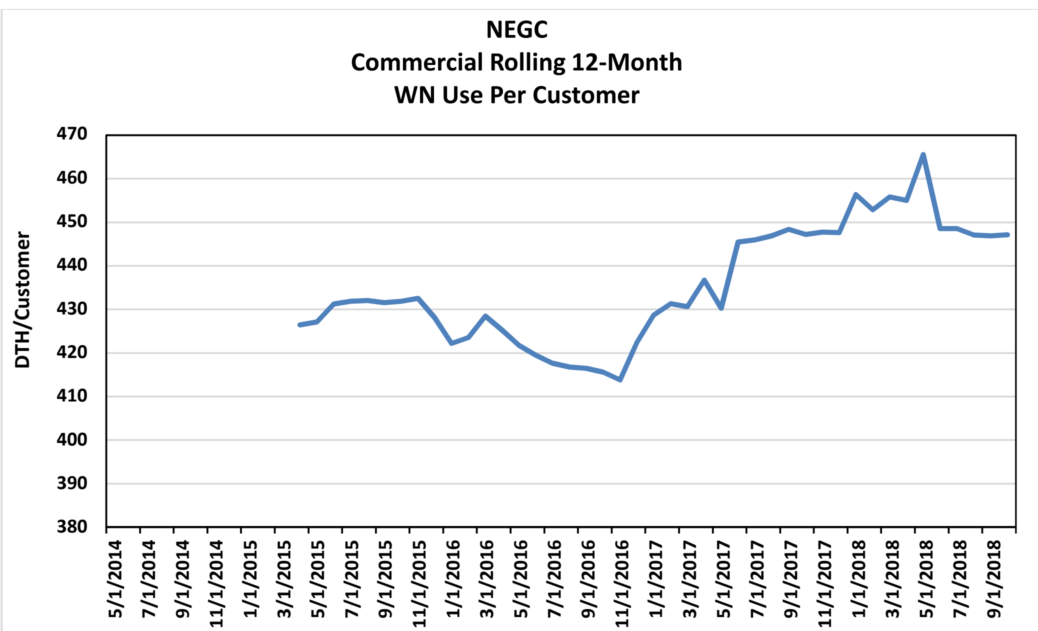

CMA
Residential Non-Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
21
20.5
20
19.5
19
18.5
18
17.5
17
16.5
16
15.5
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

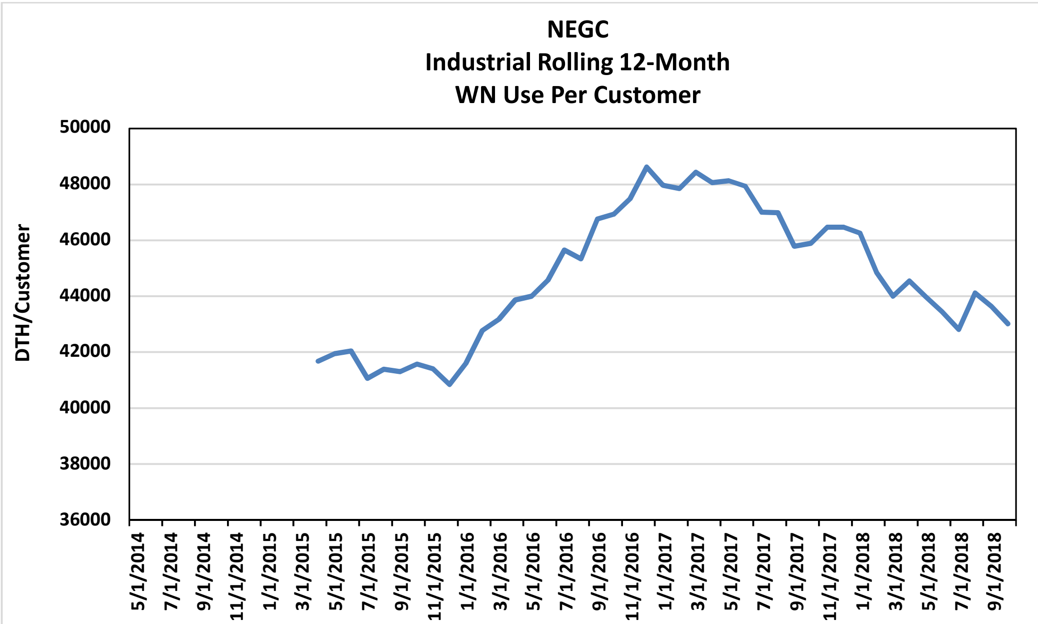

CMA
Residential Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
100
98
96
94
92
90
88
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


CMA
C&I LLF Rolling 12-Month
WN Use Per Customer
DTH/Customer
620
610
600
590
580
570
560
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

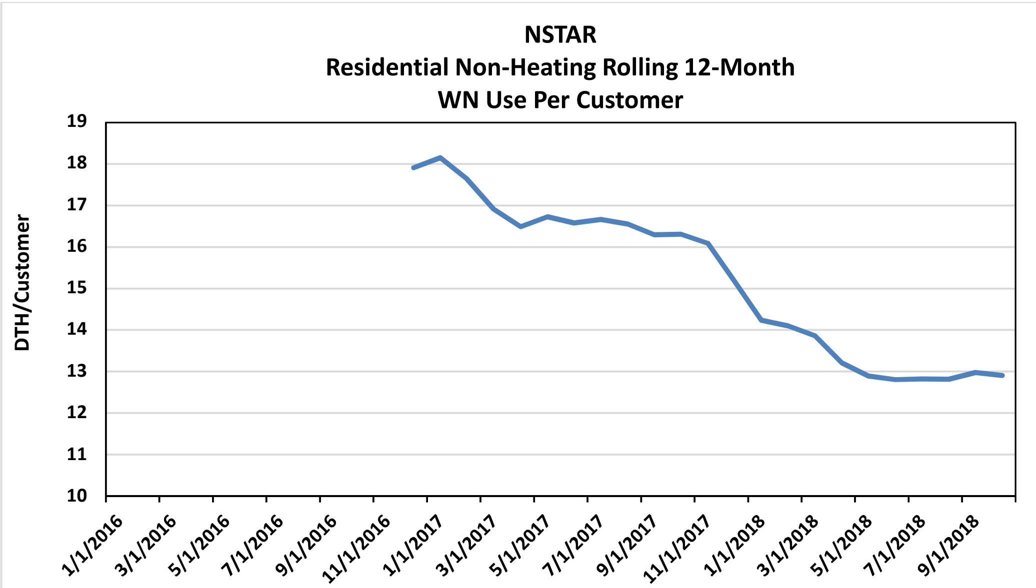
NEGC

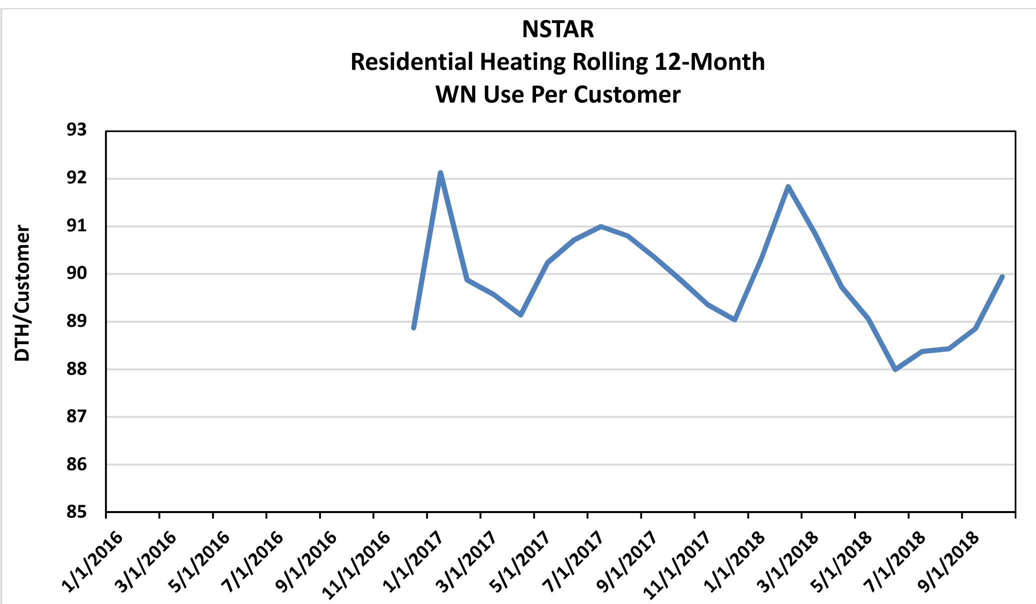

NEGC
Residential Rolling 12-Month
WN Use Per Customer
DTH/Customer
81
80
79
78
77
76
75
74
73
72
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NEGC
Commercial Rolling 12-Month
WN Use Per Customer
DTH/Customer
470
460
450
440
430
420
410
400
390
380
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

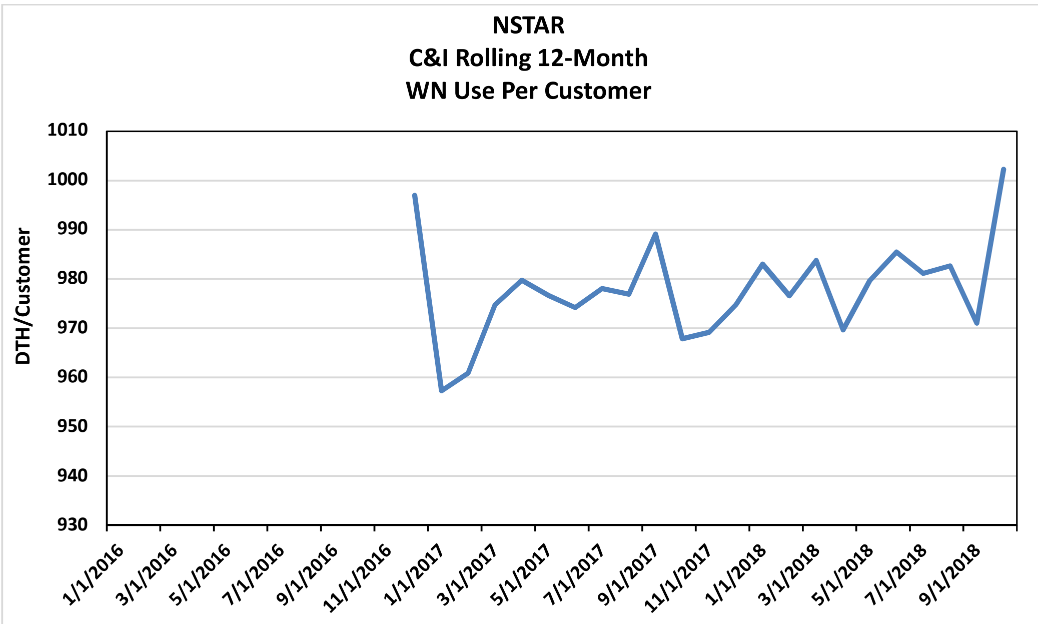

NEGC
Industrial Rolling 12-Month
WN Use Per Customer
DTH/Customer
50000
48000
46000
44000
42000
40000
38000
36000
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

NSTAR

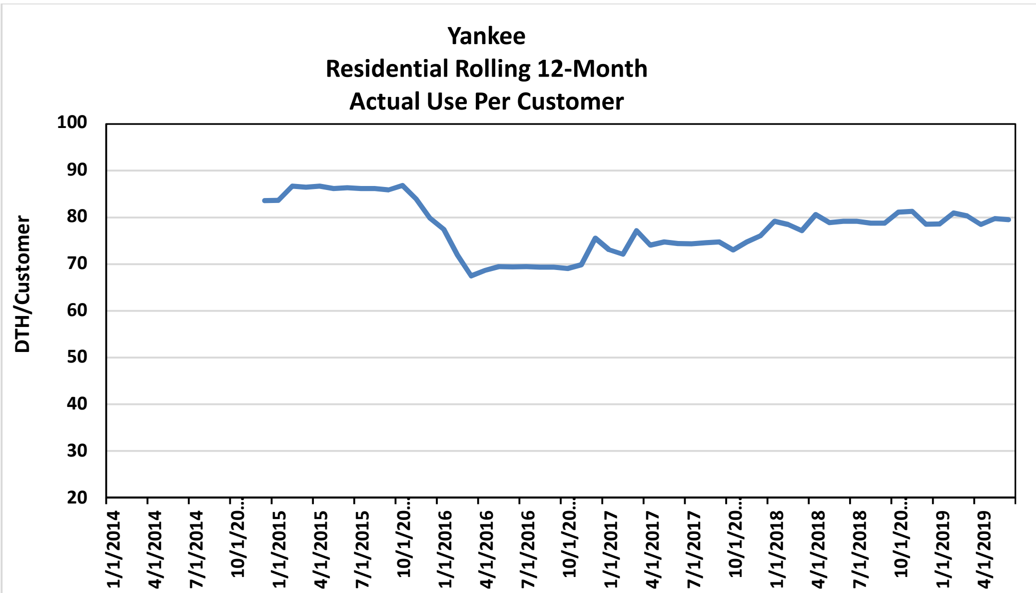


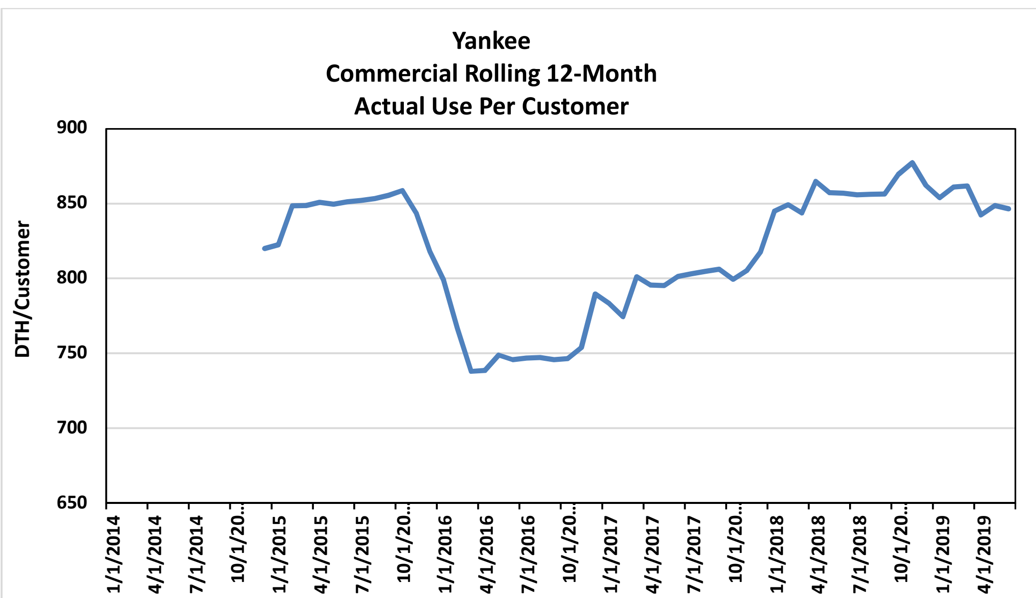


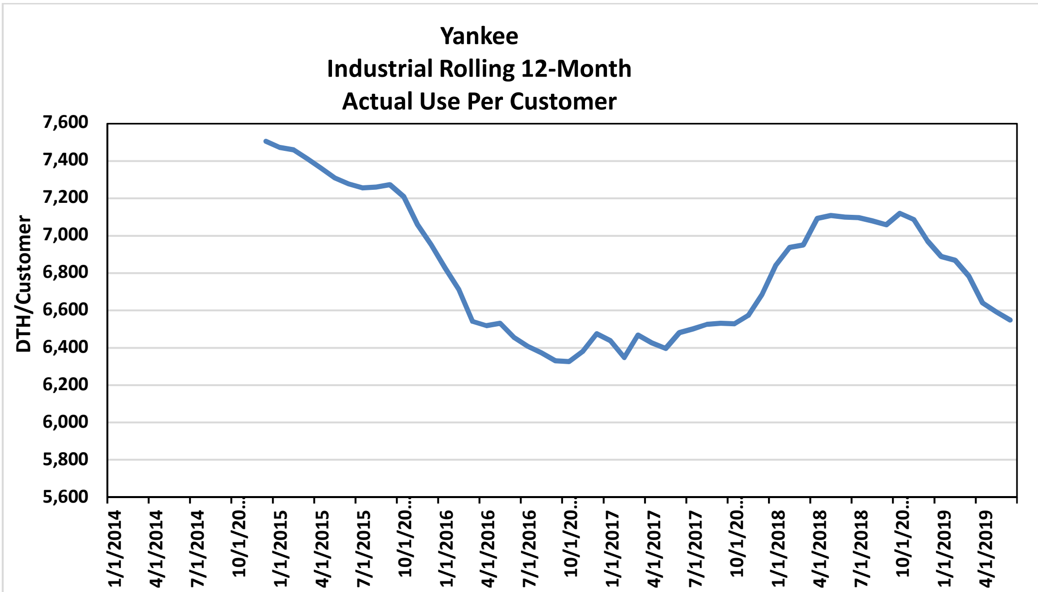
000081


NSTAR
C&I Rolling 12-Month
WN Use Per Customer
DTH/Customer
1010
1000
990
980
970
960
950
940
930
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

YGS


Yankee
Residential Rolling 12-Month
Actual Use Per Customer
DTH/Customer
100
90
80
70
60
50
40
30
20
1/1/2014
4/1/2014
7/1/2014
10/1/20…
1/1/2015
4/1/2015
7/1/2015
10/1/20…
1/1/2016
4/1/2016
7/1/2016
10/1/20…
1/1/2017
4/1/2017
7/1/2017
10/1/20…
1/1/2018
4/1/2018
7/1/2018
10/1/20…
1/1/2019
4/1/2019


Yankee
Commercial Rolling 12-Month
Actual Use Per Customer
DTH/Customer
900
850
800
750
700
650
1/1/2014
4/1/2014
7/1/2014
10/1/20…
1/1/2015
4/1/2015
7/1/2015
10/1/20…
1/1/2016
4/1/2016
7/1/2016
10/1/20…
1/1/2017
4/1/2017
7/1/2017
10/1/20…
1/1/2018
4/1/2018
7/1/2018
10/1/20…
1/1/2019
4/1/2019


Yankee
Industrial Rolling 12-Month
Actual Use Per Customer
DTH/Customer
7,600
7,400
7,200
7,000
6,800
6,600
6,400
6,200
6,000
5,800
5,600
1/1/2014
4/1/2014
7/1/2014
10/1/20…
1/1/2015
4/1/2015
7/1/2015
10/1/20…
1/1/2016
4/1/2016
7/1/2016
10/1/20…
1/1/2017
4/1/2017
7/1/2017
10/1/20…
1/1/2018
4/1/2018
7/1/2018
10/1/20…
1/1/2019
4/1/2019

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
November 2022 – October 2023 LDAC
Revenue Decoupling Adjustment Factor (RDAF)

	Residential		
1	Residential Projected October 31, 2022 Reconciliation Balance of Prior Recoveries / (Refunds)	$307,157	Sch 4, Pg 2 Col. I Line 16 + Col. M Line 16
2	Residential Revenue Decoupling Deficiency / (Excess) - Current Decoupling Period	$2,551,253	Sch 4, Pg 3 Line 10
3	Total Residential Revenue Decoupling Deficiency / (Excess) - October 31, 2022	$2,858,410	Line 1 + Line 2
4	Estimated Residential November 2022 - October 2023 Sales (therms)	67,543,787	Company Forecast
5	Residential Revenue Decoupling Adjustment Factor rate per therm November 2022 - October 2023	$0.0423	Line 3 / Line 4
	Commercial		
6	Commercial Projected October 31, 2022 Reconciliation Balance of Prior Recoveries / (Refunds)	$420,513	Sch 4, Pg 2 Col. I Line 41 + Col. M Line 41
7	Commercial Revenue Decoupling Deficiency / (Excess) - Current Decoupling Period	$232,515	Sch 4, Pg 3 Line 20
8	Total Commercial Revenue Decoupling Deficiency / (Excess) - October 31, 2022	$653,028	Line 6 + Line 7
9	Estimated Commercial November 2022 - October 2023 Sales (therms)	118,794,774	Company Forecast
10	Commercial Revenue Decoupling Adjustment Factor rate per therm November 2022 - October 2023	$0.0055	Line 8 / Line 9

000085

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Revenue Decoupling Reconcilation
Reconciliation of Previous Period November 2021 – October 2022

	Line	Month	Beginning Balance	Collections	(Over)/Under Ending Balance	Balance Subject to Interest	Interest Rate	Days per Month	Interest	Cumulative Interest
	1	**Residential**								
	3		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	4	DY 20/21 Deficiency/(Surplus)	$1,431,746							
	5	Nov-21	$1,039,034	$87,443	$1,126,477	$1,082,756	3.25%	30	$2,892	$2,892
	6	Dec-21	$1,129,369	($102,982)	$1,026,387	$1,077,878	3.25%	31	$2,975	$5,868
	7	Jan-22	$1,029,362	($146,295)	$883,068	$956,215	3.25%	31	$2,639	$8,507
	8	Feb-22	$885,707	($179,954)	$705,754	$795,730	3.25%	28	$1,984	$10,491
	9	Mar-22	$707,737	($149,368)	$558,369	$633,053	3.25%	31	$1,747	$12,238
	10	Apr-22	$560,117	($103,150)	$456,966	$508,542	3.50%	30	$1,463	$13,701
	11	May-22	$458,429	($60,488)	$397,942	$428,186	3.50%	31	$1,273	$14,974
	12	Jun-22	$399,215	($27,256)	$371,959	$385,587	4.00%	30	$1,268	$16,242
	13	Jul-22	$373,226	($17,818)	$355,408	$364,317	4.75%	31	$1,470	$17,711
	14	Aug-22	$356,878	($16,434)	$340,444	$348,661	5.50%	31	$1,629	$19,340
*	15	Sep-22	$342,072	($17,136)	$324,936	$333,504	5.50%	30	$1,508	$20,848
*	16	Oct-22	$326,443	($20,763)	$305,681	$316,062	5.50%	31	$1,476	$22,324
	17	Total		($754,201)					$22,324	

Line		
19	**Projected Cumulative Collection**	**($754,201)**
20	**Total Approved Collection**	**$1,039,034**
21	**(Over)/Under Collection, excluding interest**	**$284,833**
22	**Cumulative Interest**	**$22,324**
23	**Total (Over)/Under Collection, incuding interest**	**$307,157**

	Line	Month	Beginning Balance	Collections	(Over)/Under Ending Balance	Balance Subject to Interest	Interest Rate	Days per Month	Interest	Cumulative Interest
	26	**Commercial**								
	28		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	29	DY 20/21 Deficiency/(Surplus)	$943,031							
	30	Nov-21	$677,519	$98,009	$775,527	$726,523	3.25%	30	$1,941	$1,941
	31	Dec-21	$777,468	($42,314)	$735,154	$756,311	3.25%	31	$2,088	$4,028
	32	Jan-22	$737,241	($49,658)	$687,583	$712,412	3.25%	31	$1,966	$5,995
	33	Feb-22	$689,550	($66,175)	$623,375	$656,462	3.25%	28	$1,637	$7,631
	34	Mar-22	$625,012	($60,403)	$564,608	$594,810	3.25%	31	$1,642	$9,273
	35	Apr-22	$566,250	($43,469)	$522,781	$544,516	3.50%	30	$1,566	$10,840
	36	May-22	$524,347	($30,800)	$493,547	$508,947	3.50%	31	$1,513	$12,353
	37	Jun-22	$495,060	($20,842)	$474,218	$484,639	4.00%	30	$1,593	$13,946
	38	Jul-22	$475,812	($14,440)	$461,372	$468,592	4.75%	31	$1,890	$15,836
*	39	Aug-22	$463,262	($14,154)	$449,108	$456,185	5.50%	31	$2,131	$17,967
*	40	Sep-22	$451,239	($16,562)	$434,677	$442,958	5.50%	30	$2,002	$19,970
*	41	Oct-22	$436,679	($18,164)	$418,515	$427,597	5.50%	31	$1,997	$21,967
	42	Total		($278,973)					$21,967	

Line		
44	**Projected Cumulative Collection**	**($278,973)**
45	**Total Approved Collection**	**$677,519**
46	**(Over)/Under Collection, excluding interest**	**$398,545**
47	**Cumulative Interest**	**$21,967**
48	**Total (Over)/Under Collection, incuding interest**	**$420,513**

50 **References:**

Line		
51	(a)	Line 4 (Res) and Line 29 (Com): DG 21-130, revised with actuals through August 2021
52	(b)	Company records
53	(c)	Column (a) + Column (b)
54	(d)	[Column (a) + Column (c)] ÷ 2
55	(e)	Prime Rate effective first of each month
56	(f)	Days per month
57	(g)	[Column (d) x ((Column (e) / 365) * Column (f))]
58	(h)	Column (g) + Prior Month Column (h)
59	*	Projected

000086

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
September 2021 through August 2022
Revenue Decoupling Activity by Sector

	RESIDENTIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)
1	**FOR THE MONTH OF:**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**
2	**DAYS IN MONTH**	**30**	**31**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
3	Over Under Beginning Balance	$ -	$ 187,568	$ 921,342	$ 1,529,463	$ 1,951,823	$ 1,933,976	$ 2,352,273	$ 2,447,842	$ 2,334,214	$ 2,332,558	$ 2,449,586	$ 2,439,812
4	Monthly revenue difference Inc/(Dec) revenue	$ 170,543	$ 695,995	$ 602,442	$ 288,165	$ (52,190)	$ 276,867	$ (263,559)	$ (180,617)	$ (103,419)	$ 59,549	$ (67,861)	$ 105,253
5	True up	$ 16,775	$ 36,250	$ 2,410	$ 129,397	$ 28,989	$ 136,093	$ 352,512	$ 60,121	$ 94,837	$ 49,631	$ 48,244	$ (5,442)
6	Ending Balance Pre-Interest	$ 187,318	$ 919,814	$ 1,526,194	$ 1,947,025	$ 1,928,621	$ 2,346,936	$ 2,441,226	$ 2,327,345	$ 2,325,632	$ 2,441,738	$ 2,429,969	$ 2,539,622
7	Month's Average Balance	$ 93,659	$ 553,691	$ 1,223,768	$ 1,738,244	$ 1,940,222	$ 2,140,456	$ 2,396,749	$ 2,387,594	$ 2,329,923	$ 2,387,148	$ 2,439,777	$ 2,489,717
8	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.50%	3.50%	4.00%	4.75%	5.50%
9	Interest Applied	$ 250	$ 1,528	$ 3,269	$ 4,798	$ 5,356	$ 5,336	$ 6,616	$ 6,868	$ 6,926	$ 7,848	$ 9,843	$ 11,630
10	Ending Balance	**$ 187,568**	**$ 921,342**	**$ 1,529,463**	**$ 1,951,823**	**$ 1,933,976**	**$ 2,352,273**	**$ 2,447,842**	**$ 2,334,214**	**$ 2,332,558**	**$ 2,449,586**	**$ 2,439,812**	**$ 2,551,253**

	COMMERCIAL & INDUSTRIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)
11	**FOR THE MONTH OF:**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**
12	**DAYS IN MONTH**	**30**	**31**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
13	Over Under Beginning Balance	$ -	$ 46,351	$ (184,811)	$ (1,155,183)	$ (1,027,733)	$ (2,041,973)	$ (213,584)	$ 79,689	$ (311,294)	$ 126,301	$ 131,532	$ 217,203
14	Monthly revenue difference Inc/(Dec) revenue	$ 43,875	$ (239,968)	$ (949,941)	$ 25,392	$ (1,055,358)	$ 1,765,498	$ 9,429	$ (364,478)	$ 249,240	$ (59,661)	$ 90,541	$ (54,411)
15	True up	$ 2,414	$ 8,997	$ (18,644)	$ 105,067	$ 45,348	$ 65,699	$ 284,028	$ (26,173)	$ 188,630	$ 64,469	$ (5,572)	$ 68,675
16	Ending Balance Pre-Interest	$ 46,290	$ (184,620)	$ (1,153,395)	$ (1,024,724)	$ (2,037,742)	$ (210,776)	$ 79,874	$ (310,962)	$ 126,576	$ 131,109	$ 216,501	$ 231,467
17	Month's Average Balance	$ 23,145	$ (69,134)	$ (669,103)	$ (1,089,953)	$ (1,532,737)	$ (1,126,374)	$ (66,855)	$ (115,636)	$ (92,359)	$ 128,705	$ 174,017	$ 224,335
18	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.50%	3.50%	4.00%	4.75%	5.50%
19	Interest Applied	$ 62	$ (191)	$ (1,787)	$ (3,009)	$ (4,231)	$ (2,808)	$ (185)	$ (333)	$ (275)	$ 423	$ 702	$ 1,048
20	Ending Balance	**$ 46,351**	**$ (184,811)**	**$ (1,155,183)**	**$ (1,027,733)**	**$ (2,041,973)**	**$ (213,584)**	**$ 79,689**	**$ (311,294)**	**$ 126,301**	**$ 131,532**	**$ 217,203**	**$ 232,515**

21	Total Ending Balance	**$ 233,919.74**	**$ 736,531.39**	**$ 374,279.82**	**$ 924,090.05**	**$ (107,996.70)**	**$ 2,138,688.79**	**$ 2,527,530.75**	**$ 2,022,919.52**	**$ 2,458,858.79**	**$ 2,581,118.33**	**$ 2,657,014.89**	**$ 2,783,767.73**

000087

Attachment 9 : DOE calculation

Source: calculation based on Liberty's submission from December 8, 2022 - Tab titled "Sch4 RDAF Page 3"

ENNE + Keene : RDAF Revenue Deficiency Composition in $ - Residential vs C&I

	Residential	C&I	Total
Monthly revenue difference			
Inc/(Dec) revenue	$ 1,531,167	$ (539,840)	$ 991,327
True up	$ 949,817	$ 782,938	$ 1,732,755
Interest Applied	$ 70,268	$ (10,583)	$ 59,686
TOTAL	$ 2,551,253	$ 232,515	$ 2,783,768
	0	0	0
%	92%	8%	100%

ENNE + Keene : RDAF Revenue Deficiency Composition in % - Residential vs C&I

	Residential	C&I
Monthly revenue difference		
Inc/(Dec) revenue	55%	-19%
True up	34%	28%
Interest Applied	2.5%	-0.4%
TOTAL	92%	8%

ENNE + Keene : RDAF Revenue Deficiency

	ENNE + Keene	%
Monthly revenue difference		
Inc/(Dec) revenue	$ 991,327	36%
True up	$ 1,732,755	62%
Interest Applied	$ 59,686	2%
TOTAL	$ 2,783,768	100%

ENNE : RDAF Revenue Deficiency Composition

	ENNE	%
Monthly revenue difference		
Inc/(Dec) revenue	$ 1,531,167	60%
True up	$ 949,817	37%
Interest Applied	$ 70,268	3%
TOTAL	$ 2,551,253	100%

Keene : RDAF Revenue Deficiency

	Keene	%
Monthly revenue difference		
Inc/(Dec) revenue	$ (539,840)	-232%
True up	$ 782,938	337%
Interest Applied	$ (10,583)	-5%
TOTAL	$ 232,515	100%

000088

Attachment 10 : Actual Revenue vs Adjusted Actual Revenue

Source: calculation based on Liberty's Data Response (DR) from DR Set 3 and Technical Session (May 30, 2023) in DG 22-045

ENNE + Keene : Actual Revenue vs Adjusted Actual Revenue

	ENNE + Keene	% of Adj. Actual Revenue
Allowed Revenue (Estimated)	$ 91,749,158	101%
Actual Revenue	$ 89,082,025	98%
Adjustments to actual revenue:	$ -	
(Less): MEP Premium	$ (112,267)	-0.12%
Add: Low Income	$ 1,228,786	1.35%
Add/(less): Unbilled daily meter change from prior month	$ 6,909	0.01%
Add/(less): Unbilled revenue change from prior month	$ 552,380	0.61%
Adjusted Actual Revenue	$ 90,757,832	100%
Revenue Decoupling Adjustment	$ 991,327	1.1%
Ture-up Revenue (to account for trued-up Equivalent Bill counts)	$ 1,739,360	1.9%
Adjusted Allowed Revenue	$ 93,488,518	103%
Updated Revenue Decoupling Adjustment	$ 2,730,686	3.0%

ENNE : Actual Revenue vs Adjusted Actual Revenue

	ENNE	% of Adj. Actual Revenue
Allowed Revenue (Estimated)	$ 90,538,079	101%
Actual Revenue	$ 88,102,416	98%
Adjustments to actual revenue:		
(Less): MEP Premium	$ (112,267)	-0.13%
Add: Low Income	$ 1,228,786	1.37%
Add/(less): Unbilled daily meter change from prior month	$ 4,899	0.01%
Add/(less): Unbilled revenue change from prior month	$ 539,679	0.60%
Adjusted Actual Revenue	$ 89,763,512	100%
Revenue Decoupling Adjustment	$ 774,567	0.9%
Ture-up Revenue (to account for trued-up Equivalent Bill counts)	$ 1,735,718	1.9%
Adjusted Allowed Revenue	$ 92,273,797	103%
Updated Revenue Decoupling Adjustment	$ 2,510,285	2.8%

Keene : Actual Revenue vs Adjusted Actual Revenue

	Keene	% of Adj. Actual Revenue
Allowed Revenue (Estimated)	$ 1,211,079	122%
Actual Revenue	$ 979,609	99%
Adjustments to actual revenue:		
(Less): MEP Premium	$ -	0.00%
Add: Low Income	$ -	0.00%
Add/(less): Unbilled daily meter change from prior month	$ 2,010	0.20%
Add/(less): Unbilled revenue change from prior month	$ 12,701	1.28%
Adjusted Actual Revenue	$ 994,320	100%
Revenue Decoupling Adjustment	$ 216,760	21.8%
Ture-up Revenue (to account for trued-up Equivalent Bill counts)	$ 3,642	0.4%
Adjusted Allowed Revenue	$ 1,214,721	122%
Updated Revenue Decoupling Adjustment	$ 220,402	22.2%

000089

Revenue Decoupling Surplus/Shortfall Calculation - Actual Revenue vs Adjusted Actual Revenue

Source: calculation based on Liberty's Data Response (DR) from DR Set 3 and Technical Session (May 30, 2023) in DG 22-045

	Decoupling Year 4 2021/2022													
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	TOTAL	
ENNG + KEENE	09-2021	10-2021	11-2021	12-2021	01-2022	02-2022	03-2022	04-2022	05-2022	06-2022	07-2022	08-2022		
Allowed Revenue (Estimated)	**$3,760,450**	**$5,420,344**	**$8,863,926**	**$12,245,906**	**$14,141,423**	**$12,281,156**	**$11,218,548**	**$7,493,508**	**$5,158,868**	**$3,807,819**	**$3,527,357**	**$3,829,853**	**$91,749,158**	Allowed Revenue (Estimated)
Actual Revenue	$3,522,365	$3,706,991	$5,300,761	$10,126,798	$12,453,702	$13,202,727	$12,696,170	$9,967,686	$6,647,832	$4,349,146	$3,606,869	$3,500,979	$89,082,025	Actual Revenue
Adjustments to actual revenue:														Adjustments to actual revenue:
(Less): MEP Premium	($3,947)	($4,393)	($6,649)	($12,119)	($16,478)	($16,956)	($16,057)	($13,396)	($8,505)	($5,199)	($4,454)	($4,114)	($112,267)	(Less): MEP Premium
Add: Low Income	$354	$422	$21,904	$175,827	$214,998	$241,964	$247,869	$198,744	$109,319	$4,621	$6,513	$6,251	$1,228,786	Add: Low Income
Add/(less): Unbilled daily meter change from prior month	$7,375	$27,480	$428,230	($29,573)	$156,367	($165,002)	($38,412)	($113,085)	($266,403)	($26,412)	($4,601)	$30,944	$6,909	Add/(less): Unbilled daily meter change from prior month
Add/(less): Unbilled revenue change from prior month	$19,885	$1,233,817	$3,467,179	$1,671,417	$2,440,382	($3,014,578)	($1,416,893)	($2,001,347)	($1,478,559)	($514,224)	($99,649)	$244,952	$552,380	Add/(less): Unbilled revenue change from prior month
Adjusted Actual Revenue	**$3,546,031**	**$4,964,317**	**$9,211,425**	**$11,932,349**	**$15,248,971**	**$10,248,154**	**$11,472,678**	**$8,038,603**	**$5,003,685**	**$3,807,931**	**$3,504,677**	**$3,779,011**	**$90,757,832**	Adjusted Actual Revenue
Revenue Decoupling Adjustment	**$214,418**	**$456,027**	**($347,499)**	**$313,557**	**($1,107,548)**	**$2,033,002**	**($254,129)**	**($545,095)**	**$155,183**	**($112)**	**$22,680**	**$50,841**	**$991,327**	Revenue Decoupling Adjustment
Ture-up Revenue (to account for trued-up Equivalent Bill counts)	$50,383	$115,618	$302,265	$299,855	$297,030	$268,343	$97,560	$167,820	$42,322	$13,321	$55,850	$28,994	$1,739,360	Ture-up Revenue (to account for trued-up Equivalent Bill counts)
Adjusted Allowed Revenue	**$3,810,833**	**$5,535,962**	**$9,166,191**	**$12,545,761**	**$14,438,453**	**$12,549,499**	**$11,316,108**	**$7,661,328**	**$5,201,190**	**$3,821,140**	**$3,583,208**	**$3,858,846**	**$93,488,518**	Adjusted Allowed Revenue
Updated Revenue Decoupling Adjustment	$264,801	$571,645	($45,234)	$613,412	($810,518)	$2,301,345	($156,569)	($377,275)	$197,505	$13,209	$78,531	$79,835	$2,730,686	Updated Revenue Decoupling Adjustment
Check	($0)	($0)	$0	$0	$0	$0	($0)	$0	$0	$0	$0	($0)	($0)	Check

Revenue Decoupling Surplus/Shortfall Calculation - Comparison of Allowed vs Actual

	Decoupling Year 4 2021/2022													
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	TOTAL	
ENNG	09-2021	10-2021	11-2021	12-2021	01-2022	02-2022	03-2022	04-2022	05-2022	06-2022	07-2022	08-2022		**ENNG**
Allowed Revenue (Estimated)	**$3,707,599**	**$5,347,645**	**$8,748,973**	**$12,094,635**	**$13,963,157**	**$12,110,542**	**$11,076,620**	**$7,396,028**	**$5,088,064**	**$3,753,796**	**$3,476,313**	**$3,774,707**	**$90,538,079**	Allowed Revenue (Estimated)
Actual Revenue	$3,474,870	$3,657,441	$5,224,732	$10,012,418	$12,323,394	$13,074,818	$12,577,370	$9,877,673	$6,575,755	$4,298,576	$3,558,148	$3,447,222	$88,102,416	Actual Revenue
Adjustments to actual revenue:														Adjustments to actual revenue:
(Less): MEP Premium	($3,947)	($4,393)	($6,649)	($12,119)	($16,478)	($16,956)	($16,057)	($13,396)	($8,505)	($5,199)	($4,454)	($4,114)	($112,267)	(Less): MEP Premium
Add: Low Income	$354	$422	$21,904	$175,827	$214,998	$241,964	$247,869	$198,744	$109,319	$4,621	$6,513	$6,251	$1,228,786	Add: Low Income
Add/(less): Unbilled daily meter change from prior month	$4,584	$18,435	$405,722	($27,487)	$140,476	($140,892)	($28,296)	($102,663)	($261,166)	($29,342)	($5,768)	$31,297	$4,899	Add/(less): Unbilled daily meter change from prior month
Add/(less): Unbilled revenue change from prior month	$19,885	$1,233,817	$3,466,467	$1,669,561	$2,437,933	($3,017,226)	($1,419,801)	($2,002,937)	($1,479,093)	($514,230)	($99,649)	$244,952	$539,679	Add/(less): Unbilled revenue change from prior month
Adjusted Actual Revenue	**$3,495,745**	**$4,905,722**	**$9,112,175**	**$11,818,200**	**$15,100,323**	**$10,141,708**	**$11,361,085**	**$7,957,421**	**$4,936,311**	**$3,754,425**	**$3,454,790**	**$3,725,607**	**$89,763,512**	Adjusted Actual Revenue
Revenue Decoupling Adjustment	**$211,854**	**$441,923**	**($363,202)**	**$276,435**	**($1,137,166)**	**$1,968,833**	**($284,465)**	**($561,392)**	**$151,752**	**($629)**	**$21,523**	**$49,101**	**$774,567**	Revenue Decoupling Adjustment
Ture-up Revenue (to account for trued-up Equivalent Bill counts)	$49,912	$114,008	$300,667	$293,424	$295,631	$281,622	$95,878	$165,829	$41,712	$12,828	$55,442	$28,763	$1,735,718	Ture-up Revenue (to account for trued-up Equivalent Bill counts)
Adjusted Allowed Revenue	**$3,757,511**	**$5,461,654**	**$9,049,640**	**$12,388,059**	**$14,258,788**	**$12,392,164**	**$11,172,498**	**$7,561,858**	**$5,129,775**	**$3,766,624**	**$3,531,755**	**$3,803,470**	**$92,273,797**	Adjusted Allowed Revenue
Updated Revenue Decoupling Adjustment	$261,766	$555,932	($62,535)	$569,859	($841,536)	$2,250,456	($188,587)	($395,563)	$193,464	$12,199	$76,965	$77,864	$2,510,285	Updated Revenue Decoupling Adjustment
Chk	($0)	($0)	$0	$0	$0	$0	($0)	$0	$0	$0	$0	($0)	($0)	Chk

000090

Docket DG 22-045
Direct Testimony of Faisal Deen Arif
and Mark Thompson
Attachment 10
Page 3 of 3

Revenue Decoupling Surplus/Shortfall Calculation - Comparison of Allowed vs Actual

	Decoupling Year 4 2021/2022													
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	TOTAL	
KEENE	09-2021	10-2021	11-2021	12-2021	01-2022	02-2022	03-2022	04-2022	05-2022	06-2022	07-2022	08-2022		**KEENE**
Allowed Revenue (Estimated)	**$52,851**	**$72,699**	**$114,953**	**$151,270**	**$178,266**	**$170,615**	**$141,929**	**$97,479**	**$70,804**	**$54,023**	**$51,045**	**$55,145**	**$1,211,079**	Allowed Revenue (Estimated)
Actual Revenue	$47,495	$49,550	$76,029	$114,380	$130,308	$127,908	$118,800	$90,013	$72,077	$50,570	$48,721	$53,757	$979,609	Actual Revenue
Adjustments to actual revenue:														Adjustments to actual revenue:
(Less): MEP Premium													$0	(Less): MEP Premium
Add: Low Income													$0	Add: Low Income
Add/(less): Unbilled daily meter change from prior month	$2,792	$9,045	$22,508	($2,087)	$15,892	($24,110)	($10,116)	($10,421)	($5,237)	$2,930	$1,166	($352)	$2,010	Add/(less): Unbilled daily meter change from prior month
Add/(less): Unbilled revenue change from prior month	$0	$0	$712	$1,855	$2,449	$2,648	$2,908	$1,590	$534	$6	$0	$0	$12,701	Add/(less): Unbilled revenue change from prior month
Adjusted Actual Revenue	**$50,287**	**$58,595**	**$99,250**	**$114,149**	**$148,648**	**$106,446**	**$111,593**	**$81,182**	**$67,373**	**$53,506**	**$49,887**	**$53,405**	**$994,320**	Adjusted Actual Revenue
Revenue Decoupling Adjustment	**$2,564**	**$14,104**	**$15,703**	**$37,121**	**$29,618**	**$64,169**	**$30,336**	**$16,298**	**$3,431**	**$517**	**$1,157**	**$1,741**	**$216,760**	Revenue Decoupling Adjustment
Ture-up Revenue (to account for trued-up Equivalent Bill counts)	$471	$1,609	$1,598	$6,431	$1,399	($13,280)	$1,682	$1,990	$610	$492	$408	$231	$3,642	Ture-up Revenue (to account for trued-up Equivalent Bill counts)
Adjusted Allowed Revenue	**$53,322**	**$74,308**	**$116,550**	**$157,701**	**$179,665**	**$157,335**	**$143,610**	**$99,470**	**$71,415**	**$54,516**	**$51,453**	**$55,376**	**$1,214,721**	Adjusted Allowed Revenue
Updated Revenue Decoupling Adjustment	$3,035	$15,713	$17,301	$43,553	$31,017	$50,889	$32,018	$18,288	$4,041	$1,010	$1,566	$1,971	$220,402	Updated Revenue Decoupling Adjustment
Chk	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Chk

000091

Attachment 11: List of Liberty Accounts affecting Adjusted* Actual Revenue

* The adjustments to Actual Revenue are performed monthly but are not trued-up four months later as is the case for the Allowed Revenue

List of Accounts affecting the Gas Assistance Program (RGAP)

8840-2-0000-40-4295-4801 (Residential Revenue - Fixed); 8840-2-0000-40-4295-4802 (Residential Revenue - Variable); 8840-2-0000-40-4295-4803 (Residential Revenue - PGA); 8840-2-0000-10-1169-1756 (Deferred Residential Assistance); 8840-2-0000-52-5542-8051 (Deferred Gas Costs Residential); and 8840-2-0000-10-1920-1740 (R/A CGAC costs winter)

List of Accounts affecting the *Unbilled* Daily Meter Change from prior month

8840-2-0000-40-4460-4897 (Gas Transportation Revenue - Fixed); 8840-2-0000-40-4460-4898 (Gas Transportation Revenue - Variable); 8840-2-0000-10-1162-1730 (Accrued Utility Revenue); and for Reversing Journals: 8840-2-0000-40-4295-4813 (Commercial & Industrial Revenue - Fixed); 8840-2-0000-40-4295-4814 (Commercial & Industrial Revenue - Variable); 8840-2-0000-40-4295-4815 (Commercial & Industrial Revenue - Pass Thru); 8840-2-0000-10-1162-1730 (Accrued Utility Revenue); 8840-2-0000-52-5542-8052 (PGA Gas Pass Through - Commercial); and 8840-2-0000-10-1920-1741 (Summer Cost of Gas)

List of Accounts affecting the *Unbilled* Revenue Change from prior month

For Unbilled Revenue Recognition:
8840-2-0000-10-1162-1730 (Accrued Utility Revenue); 8840-2-0000-40-4295-4801 (Residential - Fixed); 8840-2-0000-40-4295-4802 (Residential - Variable); 8840-2-0000-40-4295-4803 (Residential - Pass thru); 8840-2-0000-40-4295-4813 (Commercial - Fixed); 8840-2-0000-40-4295-4814 (Commercial - Variable); 8840-2-0000-40-4295-4815 (Commercial - Pass Thru); 8840-2-0000-40-4460-4897 (Transportation - Fixed); 8840-2-0000-40-4460-4898 (Transportation Variable); and 8840-2-0000-40-4460-4899 (Transportation Pass Thru)

For Unbilled Commodity Cost:
8840-2-0000-52-5542-8051 (Residential - Gas Supply); 8840-2-0000-52-5542-8052 (Commercial - Gas Supply); 8840-2-0000-52-5542-8054 (Transportation- Gas Supply); 8840-2-0000-10-1920-1740 (R/A - COG Cost – Winter); and 8840-2-0000-10-1920-1741 (R/A - COG Cost - Summer)

For Unbilled Environmental Revenues:
8840-2-0000-10-1162-1730 (Accrued Utility Revenue); and 8840-2-0000-40-4460-4950 (Other Gas Revenues)

000092