REDACTED

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE REQUEST OF DOMINION ENERGY UTAH FOR APPROVAL OF A VOLUNTARY RESOURCE DECISION TO CONSTRUCT AN LNG FACILITY	)))))))))	**DOCKET NO. 18-057-03** **DPU Exhibit 2.0 Dir** **Testimony and Exhibits** **Allen R. Neale**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

DIRECT TESTIMONY AND EXHIBITS

OF

ALLEN R. NEALE

August 16, 2018

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I. INTRODUCTION AND QUALIFICATIONS

Q. Mr. Neale, please identify yourself for the record.

A. My name is Allen R. Neale. I am a Consultant working in conjunction with Daymark Energy Advisors ("Daymark"). My business address is Allen R. Neale c/o Daymark Energy Advisors, 370 Main Street, Suite 325, Worcester, MA 01608.

Q. On whose behalf are you testifying in this proceeding?

A. I am submitting testimony on behalf of the Utah Division of Public Utilities ("Division") with regard to the application filed on April 30, 2018 by Dominion Energy Utah (DEU) with the Public Service Commission of Utah (the "Commission" or "PSC") for approval of a voluntary resource decision to construct a liquefied natural gas (LNG) facility to be directly connected to its distribution system (the "Application" or the "Filing"). This matter has been designated as Docket No. 18-057-03.

Q. Please describe your educational background.

A. I received a Master's of Business Administration from Southern New Hampshire College. I also have a Bachelor of Science in Engineering Technology in Mechanical Engineering from Wentworth Institute.

Q. Please summarize your employment experience and qualifications.

A. I have over 25 years of experience in the natural gas distribution business in Massachusetts. In 1973, I joined Essex County Gas Company (then Haverhill Gas) as a Junior Engineer and subsequently held the following positions: Corrosion Engineer; Supervisor of Distribution; Administrative Assistant; Vice President of Engineering, Meter Shop and Production; and finally, Vice President of Gas Supply, Planning, Rates, Regulatory, and Environmental Matters. As these various job titles indicate, I have a broad range of experience at various levels within a gas distribution company, including field work as a distribution system corrosion engineer and as a supervisor of distribution overseeing main and service repair, replacement and new installations. Later, I was placed in charge of Department of Transportation and Massachusetts Department of Public Utilities Annual Reports for the company. My years as a Vice President provided substantial management and executive decision-making experience as well as involvement in rates and regulatory affairs. As described below, I have experience with engineering design, procurement, operation and review of LNG facilities. In 1999, following regulatory approval of the merger involving the Essex and the Boston Gas Companies, I became the President of ARN Enterprises which owned and operated CRW Finishing Company, a metal finishing business. A copy of my resume is attached as Exhibit DPU 2.1.

Q. Have you testified before this Commission?

A. No. However, I have offered testimony before other regulatory commissions as a subject matter expert in gas engineering system operations and gas network analysis modeling in support of local distribution company (LDC) accelerated capital replacement plans in numerous proceedings. Recently, I testified in several cases before state utility commissions, including:

Before the Maryland Public Service Commission:

- The three largest gas utilities applications for approval to implement a Strategic Infrastructure Development and Enhancement Plan ("STRIDE") and an associated cost recovery mechanism (Case No. 9335 Washington Gas Light, Case No. 9332 Columbia Gas of Maryland, and Case No. 9331 Baltimore Gas and Electric Company);
- Case No. 9417 in which Columbia Gas of Maryland filed an application for approval to increase rates and charges.

Before the Massachusetts Department of Public Utilities:

- Hearings on the Gas System Enhancement Plans (GSEP) filed by six separate Massachusetts gas distribution companies for review of accelerated replacement of targeted leak-prone system components. (Dockets D.P.U. 14-30 through 14-135.)

- Review of the petition filed by NSTAR Gas Company (now Eversource) in D.P.U. 14-64 to approve a proposed Gas Service Agreement ("GSA") between NSTAR Gas and Hopkinton LNG Corp. ("HOPCO"), that would replace an existing agreement for service that would have significantly changed how residential customers would have received service from HOPCO. At least partially as a result of my testimony, the D.P.U. denied NSTAR's petition.

Q. Please summarize your qualifications as a subject matter expert as it relates to the engineering design and operation of an LNG facility.

A. I have testified on numerous occasions before the Massachusetts Department of Public Utilities during my tenure as an executive of the Essex Gas Company, where I oversaw the design, procurement and installation of an upgrade to the existing LNG facility that is directly connected to that company's distribution system.

In addition to the recent cases summarized above, I have also supported Public Counsel for the State of Washington on cost-effectiveness and adequacy of service for Puget Sound Energy's proposed Tacoma LNG facility, providing expert advice through a phased review of the project, technical review sessions and settlement negotiations, with the Final Order issued in WUTC UG-151663 on November 10, 2016.

In the majority of cases summarized above, I have reviewed and submitted testimony on the appropriate specification and usefulness of gas network analysis computer models used in many local gas utility petitions to recover costs associated with infrastructure investments. These gas network analysis models are similar to the system employed by the Company to support its petition in the instant docket. My familiarity with these models allows me to assess from an engineering perspective whether the proposed infrastructure project is likely to achieve the specific improvement in system performance claimed in the petition.

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

A. I have been asked by the Division to objectively evaluate from an engineering and cost perspective the voluntary petition for recovery of costs associated with the proposed on-system LNG facility that DEU claims is necessary to meet its obligations going forward to provide reliable supply to serve firm customers.

Further, the Division has asked me to make recommendations regarding:

1) the accuracy of the models and assumptions DEU used to calculate the requirements to meet an expected supply shortfall;
2) whether the proposed LNG Facility is physically capable of meeting any shortfall;
3) whether the cost and non-cost evaluation criteria on which this voluntary petition is based was sufficiently robust for planning and resource selection purposes; and
4) whether the proposed LNG Facility will meet the standard for this resource investment to be in the public interest.

Q. What exhibits are you sponsoring?

A. In addition to this direct testimony and my resume, I am sponsoring the following Exhibits:

- DPU Exhibit 2.1 Resume of Allen R. Neale
- DPU Exhibit 2.2: Exhibit 2.2, PHMSA map of LNG facilities serving LDCs across the U.S. as of July 2017 and INGA map
- DPU Exhibit 2.3: Sample Load Duration Curve
- DPU Exhibit 2.4: American Chemical Society Abstract “Impact of Ambient Temperature on LNG Liquefaction Process Performance: Energy Efficiency and CO_2 Emissions in Cold Climates”, Steve Jackson* , Oddmar Eiksund, and Eivind Brodal, UiT-The Arctic University of Norway, Tromsø 9037, Norway, Ind. Eng. Chem. Res., 2017, 56 (12), pp 3388–3398, DOI: 10.1021/acs.iecr.7b00333, Publication Date (Web): March 8, 2017, Copyright © 2017.

- DPU Exhibit 2.5: Digital Refining (full article), “Small-scale LNG – what refrigeration technology is the best?” T Kohler & M Bruentrup, Linde Engineering, R D Key & T Edvardsson, Linde Process Plants, March 2014.
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II. EXECUTIVE SUMMARY

Q. Please summarize your findings for the Commission.

A. Based on my review and analysis to date, I find that while DEU appears to have designed a system that from a modeling perspective addresses a supply disruption consistent with recent experience, it has not met the burden of proof required in this proceeding to show that it has adequately evaluated all resources that could provide a similar remedy.

The model used by DEU shows that when the Proposed LNG Facility is connected to the selected location the Company's distribution system utilizes the full 150,000 Dth/d of the design vaporization capacity included in the Filing to meet the required operating pressure to provide reliable service at peak hours of the gas day. Whether the stated capability is needed is a separate question, requiring balancing the risks and costs of an outage against the risks and costs of a facility to avoid them.

However, the Company has not fulfilled the requirements of this Commission to provide thorough evaluation of all alternatives to the proposed LNG Facility based on both cost and non-cost criteria, including a full estimate of their cost. The solicitation for the required supply resource -- not specific technology, would be preferable to assessment of self-selected alternatives. This would ensure offerors respond to a uniform request, rather than iterative or otherwise inconsistent individual requests from the utility.

Finally, the Filing appears to assume that the Proposed LNG Facility is intended to provide reliability to both firm sales customers and Transportation only customers who are supposed to be responsible for assuring reliability of their own supply, without addressing how the latter customer class will pay for this service. But if residential customers are to be expected to pay for it through rates, then the Company should be required to provide assurance that control of the proposed LNG Facility will not transfer to any affiliate of DEU whether or not it is replaced with a contract for similar but not identical flexible service and reliability. I discuss these concerns in more detail below.

III. BURDEN OF PROOF

Q. What is the burden of proof DEU is required to meet for this Filing?

A. Under Utah Code there are two provisions under which the Company may request approval of a resource decision, with the major distinction between the two being a request for pre-approval prior to the implementation of the resource decision under Utah Code Section 54-17-402 versus a request for cost recovery in rates after the project is in service in the Company's next general rate case.[1]

The request for pre-approval was filed under Utah Code Section 54-17, and requires the filing be sufficient to allow the Commission to determine that the proposed resource is in the public interest under the provisions of subsection (3)(b) as enumerated below.[2]

> (3) In ruling on a request for approval of a resource decision, the commission shall determine whether the decision:
>
> (a) is reached in compliance with this chapter and rules made in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act; and
>
> (b) is in the public interest, taking into consideration:
>
> (i)
>
> (A) whether it will most likely result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to the retail customers of an energy utility located in this state;
>
> (B) long-term and short-term impacts;
>
> (C) risk;
>
> (D) reliability;
>
> (E) financial impacts on the energy utility; and other factors determined by the commission to be relevant.

[1] DEU Exhibit 1.0 Direct Testimony of Kelly Mendenhall, page 12, lines 283-288

[2] https://le.utah.gov/xcode/Title54/Chapter17/C54-17-S402_1800010118000101.pdf

> The Filing also must comply with the Commission's Rules. Rule 746-440-1 states that the Filing Requirements for a Request for Approval of a Resource Decision (must include) …Sufficient data, information, spreadsheets, and models to permit an analysis and verification of the conclusions reached and models used by the Energy utility.[3]

Q. What provisions of the statute cited above concern you most with the Filing?

A. I am most concerned with whether the Filing demonstrates that the Proposed LNG Facility meets the lowest reasonable cost criterion given the Standard's ability to contemplate non-cost criteria such as long-term impacts, risk and reliability. Furthermore, it is not evident that the Company's focus on a specific type of resource, rather than capabilities, is warranted. A Request for Proposals (RFP) for any type of resources that meet the purportedly-needed supply resources would result in the "lowest reasonable cost to the retail customers." (Utah Code §54-17-402(3)(b)).

Q. Does the Filing address each of these non-cost criteria?

A. Yes, to some extent the Filing explains and documents events that raise reliability concerns that could be addressed by the Proposed LNG Facility. However, to confirm the Filing represents the lowest reasonable cost option to improve reliability, the Company would have to provide more information on the alternatives it considered and rejected in favor of the Proposed LNG Facility. It would also need to show that those alternatives compared comparable services. Further, the Company discusses regulatory lag and associated credit risk should the Company proceed with construction of the Proposed LNG Facility without receiving the Commission's prior approval[4] as risks. In the absence of a Commission order requiring the Company to proceed, these "risks" should not be given much weight as they are already assumed by the Company in the

[3] https://rules.utah.gov/publicat/code/r746/r746-440.htm#T3 , section (1)(f)
[4] DEU Exhibit 1.0, page 11, lines 261-270.

normal course of utility business decisions. The Company's risk is also that of not having an adequate portfolio of gas supply choices to ensure it is able to meet its responsibility to be the supplier of last resort.

IV. SCOPE OF REVIEW

Q. Have you reviewed the Company's filing and all discovery in this proceeding?

A. I have reviewed the Company's Filing submitted April 30, 2018, including the public and confidential Direct Testimony and Exhibits of witnesses Faust, Gill, Mendenhall, Paskett and Platt. In addition, I and my colleagues at Daymark, have reviewed the Company's public and confidential responses to Discovery, including DPU sets 1 through 6, as well as responses to the first set of discovery propounded by the Utah Office of Consumer Services. As of this writing, we await receipt of responses to DPU sets 7 and 8.

V. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. What conclusions do you reach in your testimony?

A. Based on my review and the findings summarized above, I reach these conclusions:

1. The Company has shown that its network analysis model demonstrates that a strategically located resource that provides the same delivery capacity as the Proposed LNG Facility will maintain minimum systemwide operating pressures under the design peak-day supply deficiency scenarios the Company's Gas Supply Planning Department has evaluated;
2. The Proposed LNG Facility will adequately address the stated need to provide a reliable and low-cost service to firm customers, but this is not sufficient to adequately demonstrate it is most likely to be the lowest reasonable cost option;

3. The Company's reliance on ancillary benefits associated with Satellite LNG facilities is misplaced and in fact could weaken the case for the insurance the Company seeks, and therefore the Commission should not give the purported benefits any weight in favor of the facility.
4. The Filing does not meet the burden of proof for the Proposed LNG Facility to be in the public interest.
5. If it wishes to proceed, the Company should be required to supplement its Filing, or make a new one, to:
    a. More fully evaluate opportunities to incorporate supplies that are less costly than the Wexpro supply presumed to be used to fill the Proposed LNG Facility prior to receiving the Commission's order in this docket.
    b. Demonstrate that a technology-neutral RFP for the required supply resources would be beneficial.
    c. Identify all existing contracts that it would not need to retain or extend once the proposed LNG Facility is in-service.
    d. Conversely, explain why certain contracts that it recently negotiated as interim options with primary terms ending before 2022 could not be extended or renegotiated to continue beyond the in-service date of the Proposed LNG Facility in order to facilitate a new RFP.
6. The Filing lacks assurance that control of the proposed LNG Facility will remain with the Company and not be transferred to any affiliate of DEU, whether or not it is replaced with a contract for similar but not identical flexible service and reliability, as I discuss in the section "Other Concerns" below.
7. The Company has not stated in this Filing that it would not sell or displace LNG to any on- or off-system customers before or during the period of potential design winter send-out conditions.

Q. What recommendations do you make based on your conclusions?

A. Based on my conclusions I respectfully suggest that the Commission do the following:

1. Find that the Filing does not meet the burden of proof, as summarized above, because the Company has not shown that the Proposed LNG Facility is the lowest reasonable cost option and is the proper response to the changed circumstances;
2. Find that the Company's reliance on ancillary benefits associated with satellite LNG facilities should not be considered when determining whether the Filing meets the Burden of Proof because the associated costs are unknown.
3. Find that the Filing and supporting network analysis model results confirm the ability of the Proposed LNG Facility to meet, for reliability planning purposes, a supply shortfall of 100,000 Dth/day up to 150,000 Dth/d;
4. Require the Company to evaluate the costs of all alternative options considered, even if these options do not offer to provide the full capacity required to meet the shortfall scenario for reliability planning purposes;
5. Require the Company to issue an all-source RFP to meet the identified need at the lowest reasonable cost;
6. The Company should be required to designate the Proposed LNG Facility, or another facility resulting from the RFP as a materially strategic resource under the provisions of the Merger Agreement approved in Docket 16-057-01.
7. Finally, require as a condition of approval that the Company agree that it will not transfer ownership and/or control of the proposed LNG Facility to any affiliate of DEU without prior review and approval by the Commission.

VI. OVERVIEW OF THE LNG FACILITY

Q. Please briefly summarize the proposed LNG Facility.

A. The Company has proposed to construct, own and operate an on-system LNG storage facility to be located near [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] that will include a 15 million-gallon LNG storage tank, an amine gas-pretreatment process, a liquefaction cold box, and gas vaporization facilities. The proposed liquefaction rate is equivalent to approximately 82,000 Dth/d and the proposed vaporization rate is 150 MMcfd or approximately 150,000 Dth/day.[5]

Q. How were these specifications of the Proposed LNG Facility determined?

A. My understanding from reviewing the Filing is that the Company determined that it has lost supply delivery to its city gate stations of up to 150,000 Dth/d and is seeking to find a supply source to cover such eventualities. As a result, a LNG facility with the above-mentioned size for vaporization, liquefaction and storage capacity was determined by DEU's Gas Supply and System Planning and Analysis Department. Additionally, DEU quantified how much gas could reasonably be received into the Company's system at the specified site. The System Planning Department determined that 150,000 Dth/day is the maximum volume that the system can effectively utilize at that location. I further understand that the tank size was chosen to minimize costs because larger or custom tanks would cost significantly more. The liquefaction rate was based on utilizing "standard" equipment sizing for a project of this nature as well as determining the rate in which the tank could be filled.[6]

Q. What do you mean by the Proposed LNG Facility being "effectively utilized"?

A. By effectively utilized I mean that the chosen design specifications will allow the Proposed LNG Facility to provide reliability by maintaining systemwide pressure following a supply loss of the magnitude recently experienced.[7] This objective is first defined by the vaporization rate of 150,000 Dth/day. The Company then selected a storage tank size that was a compromise between the need to provide coverage for an extended supply loss event and cost. In order to have a full tank prior to the start of winter, the Company selected liquefaction equipment that would refill the tank over the summer period. Because the liquefaction facility cost is a function of the daily rate at which LNG is created, the Company chose a design that will liquefy at a much lower rate

[5] DEU Exhibit 5.0, Direct Testimony of Michael Gill, page 2 at 26-30.
[6] DEU Exhibit 5.0, page 4 at 91-100.
[7] DEU Response to OCS 2.24 confirms this as the reason for the Proposed LNG Facility withdrawal rate.

than the 150,000 Dth/d of gas that will be re-vaporized and delivered into the distribution system.

Q. Does it make sense to choose a design that liquefies natural gas at a much slower rate than it re-vaporizes the LNG?

A. Yes, generally speaking, it does make sense and for the primary reason that this is a winter peaking facility, so it may as well take advantage of the two major cost benefits of a slower liquefaction rate. The first benefit is the fact that the cost of this module is directly related to the design rate of liquefaction. And the second cost benefit is the fact that the slower rate allows for the company to rely on smaller amounts of seasonally underutilized year-round interstate pipeline capacity to move gas supply to the Facility over the summer period. For illustration purposes, I have shown seasonally excess capacity as the blue-shaded area in Exhibit 2.3, Sample Load Duration Curve, in Section VII below.

Q. How do you know that the Company plans to use seasonally underutilized pipeline capacity to fill the LNG storage tank?

A. I don't know for sure that the Company plans to rely on seasonally excess pipeline capacity, because it is possible that the Facility could be refilled using interruptible interstate pipeline capacity. However, I do note that the Company is listed as an original shipper in the Index of Customers made public on three pipeline websites. These publicly available listings show that Dominion has access to firm transportation under specific tariffs that appear to be year-round capacity because the description of the tariff terms on the same websites call for reservation charges to be paid every month. The Index of Customers for Dominion Energy Questar Pipeline shows that Questar Gas has firm service under rate schedule TF-1 of 798,902 Dth/d.[8] Similar listings for DEU can be found in the publicly available Index of Customers listings on Kern River (KRF-1) and

[8] Questar Pipeline Informational Posting> Index of Customers> Index List. https://www.questarpipeline.com/qpc_ords/f?p=330:31:::::P0_PIPELINE:QPC

Northwest Pipeline (TF-1).

Q. Do you have any concerns about the specifications for the Proposed LNG Facility?

A. Yes, I have two concerns with the Company's stated plans for liquefaction and refill. My first concern is the Company's apparently conflicting statements regarding the number of days required to refill the storage tank, given the design of the liquefaction component of the facility design. I have noted that for the same liquefaction rate of 8.2 MMcf/d specified in Witness Gill's direct testimony,[9] the Company alternatively states that:

- it would take approximately 180 days to completely fill the proposed LNG storage tank' (correcting the number of days specified in DEU Exhibit 5.0, page 4 at 100-102; and
- it would take 150 days to fill the tank.[10]

My second concern is the Company's plan to rely upon a specific gas supply contract to refill the tank may not be consistent with least cost dispatch protocol based on variable commodity cost of gas supply. The Company will rely on its contract for Wexpro gas supply for liquefied injections instead of investigating the ability to purchase spot supply at a lower cost.[11] Further, the Company has indicated it will include in its dispatch protocol "other costs that may be incurred at the time, such as the costs of shutting in supplies." [12] However, the Company has separately confirmed that it will assess opportunities to reduce gas supply purchases during the winter that may be lower cost than Wexpro supply without such limitation.[13] I discuss this concern with the inclusion of fixed costs in dispatch protocol in more detail further below.

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[9] DEU Exhibit 5.0, page 2 at 26-30.
[10] DEU Response to DPU 2.28, first paragraph, 6/25/2018.
[11] DEU Response to DPU 1.03, 6/22/2018, second paragraph, which states that at current commodity price only, the cost to fill a 15-million-gallon tank with Wexpro rather than spot gas supply would cost an additional $225 million.
[12] DEU Response to DPU 1.03, 6/22/2018.
[13] Supply Reliability Technical Conference June 19, 2018 presentation, slide 18.

Q. What is the problem that the Company is trying to solve with this Filing?

A. The Company states in its Filing that its current portfolio can meet the Design Peak Day requirements if all gas supply in its portfolio is delivered. However, the Company also says it is unreasonable to assume that all of the gas supplies in its portfolio will show up during a Design Peak Day event and it expects supply shortfalls even during a multi-day period when temperatures are just "very cold."[14] Indeed, the Company says it has experienced several days in recent years when significant upstream supply disruptions occurred on winter days when temperatures were above DEU's Design Peak Day temperatures.[15] The Company acknowledged that it was able to manage these supply shortfall events but only because they were of relatively short duration, and because it was able to purchase incremental spot supply and utilize additional storage withdrawal capacity.[16]

Q. What evidence does the Company provide that it has correctly sized the Proposed LNG Facility to match this shortfall?

A. The Company has provided documentation that it has experienced design peak day deficiency events since 2011 that have exceeded 100,000 Dth/d and reached as high as 150,000 Dth/d.[17] The Company states that these events are beyond its control.[18,19] Because such events have occurred even on non-peak days, when these disruptions occur on design peak days, DEU is at risk of being unable to provide service to firm sales customers.[20] The Company also provided evidence that these supply shortfall events occur on an intra-day basis,[21] supporting its proposal for the Proposed LNG Facility that will be dispatchable during the day and be able to offset the same 150,000 Dth/d

[14] DEU Response to DPU 2.05, 6/25/2018.
[15] DEU Exhibit 2.0, Direct Testimony of Tina Faust, pp 3-5, lines 70-104.
[16] DEU Exhibit 2.0, page 4, lines 86-91.
[17] Supply Reliability Technical Conference, June 19, 2018 presentation, slide 11.
[18] DEU Exhibit 1.0, page 1, lines 24-25.
[19] DEU Exhibit 4.0, Direct Testimony of Bruce Paskett, page 11, lines 226-230.
[20] DEU Exhibit 2.0, page 3, lines 66-68.
[21] DPU 4.01 Attachment 1, which identifies the shortfalls by quantity, date and pipeline renomination cycle.

magnitude shortfall.

Q. Why is an LNG facility an appropriate solution to this problem?

A. The Company acknowledges that some shortfalls can be of short duration, i.e., for an intra-day period until additional supplies can be brought on through the pipeline re-nomination process.[22] The Filing assumes that the best way to solve this design peak day deficiency is to secure a resource that DEU can quickly dispatch without having to wait for confirmation of resources by third party suppliers and interstate pipelines.[23, 24] (The Company has indicated that the "current facility design", which we assume to be the Proposed LNG Facility design, is not sufficient "to meet both the peak-hour demand and supply reliability" requirements.[25]

Further, the Company has shown that it has experienced design peak day deficiency events since 2011 that have exceeded 100,000 Dth/d on six days and reached as high as 200,000 Dth/d in one day.[26] Because such events have occurred even on non-peak days, the Company concludes that an on-system facility with supply located downstream of third party resources and fully dispatchable on short notice by the Company is the best solution to address the problem not only to meet Design Day planning criteria but also under normal cold weather conditions.[27]

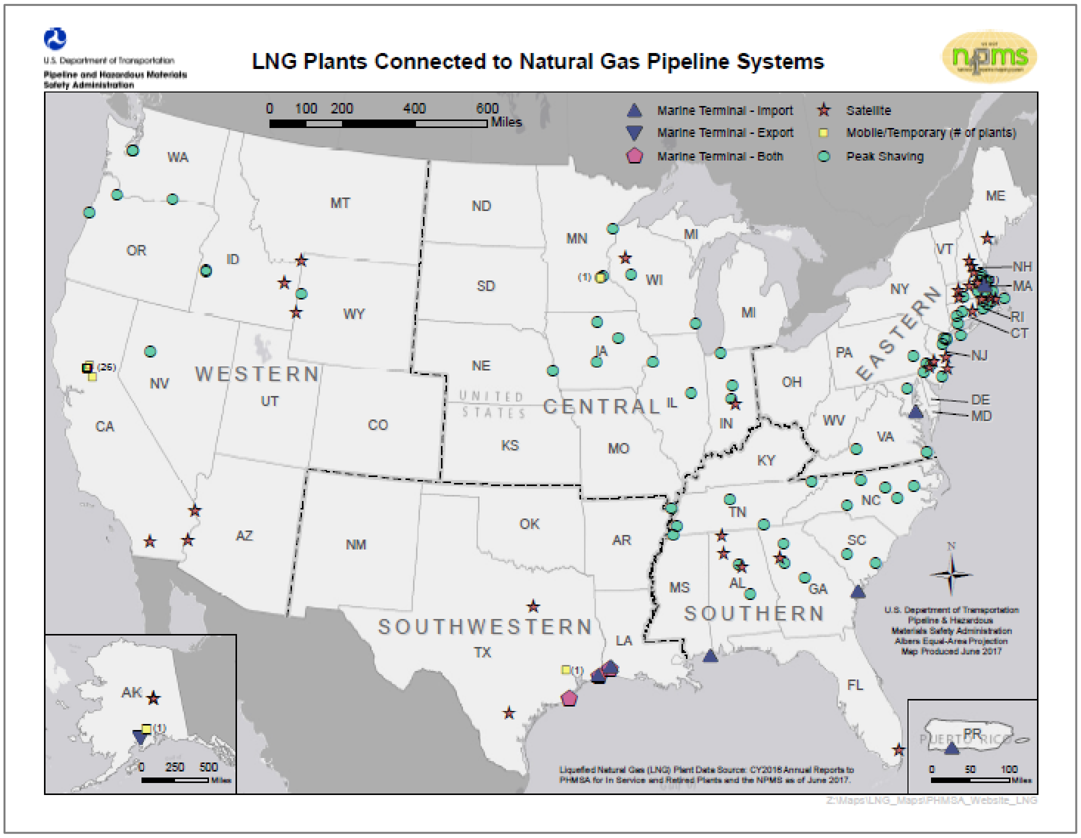
VII. CHARACTERISTICS OF LNG SERVICE

Q. Does LNG service have characteristics that make it suitable for solving the supply deficiency that DEU cites as the reason for this Filing?

[22] DEU Exhibit 3.0, Direct Testimony Michael Platt, page 11, lines 282-284
[23] DEU Exhibit 1.0, page 9, lines 220-221.
[24] DEU Exhibit 2.0, page 3, lines 59-68.
[25] Supply Reliability Technical Conference, June 19, 2018 presentation, slide 10.
[26] Supply Reliability Technical Conference, June 19, 2018 presentation, slide 11.
[27] DEU Exhibit 1.0, page 9, lines 200-204.

A. Yes, in fact, many utilities across the U.S. rely upon LNG storage facilities that convert LNG back into gas that is fed directly into the distribution system, as shown in Exhibit DPU 2.2 below.

Exhibit 2.2, PHMSA map of LNG facilities serving LDCs across the U.S. as of June 2017



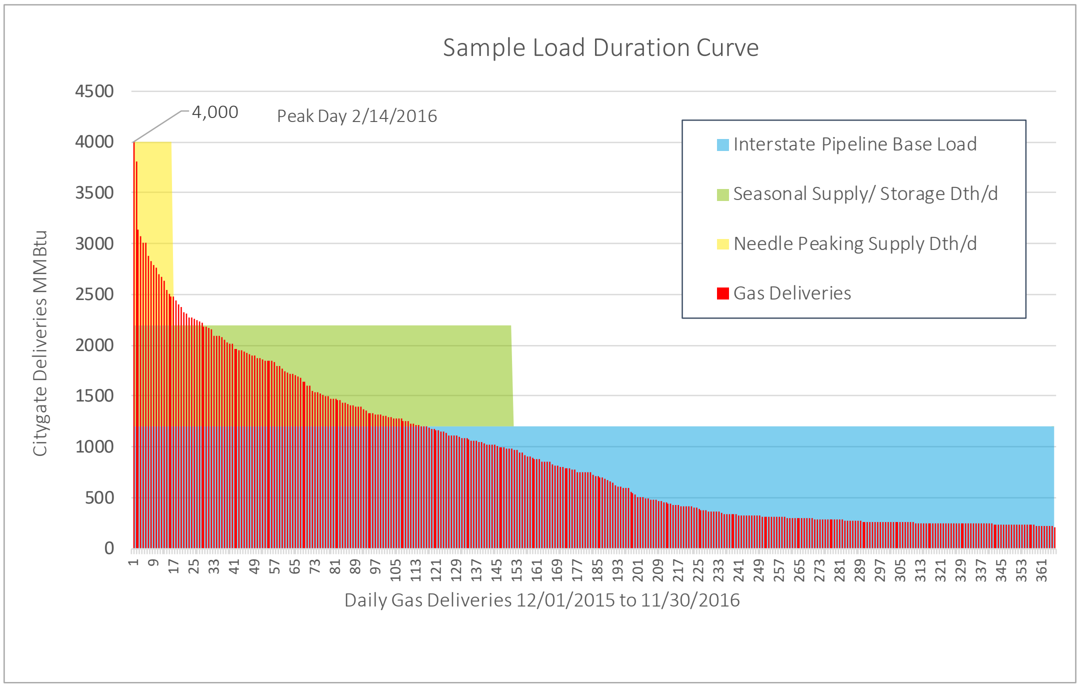
This suitability is directly due to how well the characteristics of LNG and other types of storage service match the requirements of an LDC that serve predominantly residential heating customers. It is important to note, however, that it appears that the Company plans to rely on the Proposed LNG Facility to offset peak day supply curtailments experienced by customers who do not take firm sales service from DEU but instead have chosen to be served under a transportation only tariff that requires them to provide their own third-party supply.

Q. Please describe how a typical LDC's customer base may in general support the need for LNG service?

A. LDCs consider LNG service because it satisfies the regulatory obligation to maintain a resource portfolio that meets firm customer demand under design day and extended cold snap conditions. Design weather criteria are usually based on the coldest weather experienced over the last ten to as many as thirty, fifty or 100 years. Regardless of the time frame used for these criteria, many LDCs have experienced record cold weather in the most recent ten years.

These conditions, when modeled in the form of a load duration curve, often produce a requirement to meet a significant step increase in demand above the average winter day requirement (shown in green below) for only a few days. This "needle peak" may last for only 1 or 2 days and up to as many as 15 days depending on typical weather conditions. The shape of this needle peak is represented conceptually in a typical LDC load duration curve shown in Exhibit 2.3 below highlighted in yellow.

Exhibit 2.3 Sample Load Duration Curve Chart



Under these extreme cold weather conditions, it is very likely the case that all contract baseload supplies are fully utilized, and no incremental spot supply is available. Additionally, supplies may be shuttered off because of freeze offs in the supply area. But a more expensive service such as LNG can be cost-effectively sized to address a short-lived event because it doesn't require commitment to maintain year-round firm supply commodity and transportation capacity that might have a lower average unit cost but a higher total seasonal or annual cost.

Q. What are the characteristics of LNG that make it especially suitable to meet needle peak demand?

A. LNG is ideal to meet a needle peak need or a loss of supply because it can be located on-system, sized to meet the scale of the design criteria needs of such events. LNG Facilities are available for immediate and continuously adjusted dispatch (within design limitations and operating parameters) and not subject to fixed intraday nomination cycles of an interstate pipeline.

Q: Please define LNG in layman's terms.

A. LNG is the liquid form of natural gas. It is transformed into a liquid state by cooling it until becomes a liquid. This conversion to a liquid occurs at a cryogenic temperature of −265°F (−160°C). The process of conversion to a liquid also causes the equivalent gas to shrink by a factor of approximately 600, enabling the gas to be stored in reinforced containment structures designed to economically maintain the super-cooled temperature conditions.

Q: How will the Proposed Facility create and maintain LNG?

A: Based on review of the Filing and responses to discovery, my understanding is that during the off-peak period of the year the Proposed LNG Facility will receive methane natural gas via an interconnection with an interstate pipeline and send it through a front-end liquefaction facility that cools the temperature to minus 160^{o} Celsius transforming the supply into a liquid state.[28, 29] The storage facility is constructed like a giant thermos bottle with a thick-walled double hull vessel with its annular space filled with a perlite insulation that maintains the supply in a liquid state under 2 psig until it is needed to meet needle peak demand or a pipeline supply loss in the winter season. At that time, the Facility will transform the LNG back to a gaseous state by heating the liquid in vaporizers and sending it out into the distribution system.

Q: Is the process of converting the natural gas to LNG and back to methane expensive?

A: Yes, it is more expensive on a cost per unit basis than relying on methane feed gas from the interstate pipeline or underground storage. In addition to the capital cost there are incremental operating and maintenance costs associated with the liquefaction and vaporizers that bookend the special storage unit. A full description of the cost of LNG

[28] DEU Exhibit 5.0, page 4, lines 104-110
[29] Confidential DEU Exhibit 5.02, page 6

service would not be complete without mentioning the additional land and safety requirements that must be met, plus on-going training costs. Once the unit cost for liquefaction and vaporization are added to the commodity cost of storage, however, LNG as a solution to meet short term spikes in demand can be very competitive with seasonal storage or year-round firm pipeline supply.

Q: How does fuel loss add to the cost of LNG service?

A: Fuel loss occurs due to the mechanical conversion process itself as well as heat loss that occurs due to the ambient conditions at the plant location. For example, fuel is required to run the compressors and heat exchangers used to pre-treat, super-cool and warm up the feed gas at different stages of the process. (Assuming fuel gas is used in lieu of electricity to run these components.) However, fuel loss can be minimized to some extent by facility design options, with the remainder adding to operating and maintenance costs,

Q: Can you briefly describe how LNG is affected by ambient conditions?

A: Yes, I can. By ambient conditions, I am referring to the temperature and pressure typical for the area surrounding the plant site. These conditions are important to recognize because LNG is formed through super-cooling, as described above, but quickly evaporates into its gaseous components (primarily methane) when it warms up when exposed to ambient outdoor temperature and pressure. Under safe storage conditions, however, continuous exposure to ambient air can cause small amounts of LNG to spontaneously revert to a gaseous state, this is known as boil off gas or, more generally, heat loss. The typical LNG facility includes a boil off compressor, which takes this gas, compresses it, and sends it to the distribution system resulting in very small real losses of product.

Q: Please explain how heat loss affects the LNG stored in the tank.

A: The typical LNG storage tank is a giant thermos bottle and no thermos bottle is 100% free from heat loss. As boil off occurs over time the BTU value of the product in the tank "weathers" meaning that the BTU value starts to increase because lighter BTU gas is what boils off first.[30]

When the inventory in the tank is not utilized for an extended period, the BTU value continues to rise. In order to prevent this, each year the tank needs to be adequately cycled so that enough LNG is placed in the tank to keep the BTU value close to the BTU value when the gas was liquefied. In other words, the natural tendency for LNG inventory to "weather" is addressed by the protocol set by the plant operator to cycle the inventory on an annual basis.

Q: Does heat loss occur at any other point in the operations of an LNG facility?

A: Yes, however, as I described above this heat loss when combined with fuel use required at interim stages of providing LNG peaking service comprises total fuel loss throughout the operation of the LNG facility. In addition to boil off gas described above, heat loss can also occur during the liquefaction phase, a multi-stage process that includes taking pipeline gas and stripping out everything but the mostly methane component, which is then supercooled and compressed to reach a liquid state before entering the storage tank. The fuel loss at this stage is a combination of loss due to exposure to ambient conditions because the pipeline gas is first warmed up in order for the non-methane constituents to drop out of the gas stream, as well as the fuel use required to run the compressors.

Q: Does fuel loss occur during withdrawal from the LNG facility as well?

A: Yes, fuel use is needed to run the vaporizers at the re-gasification stage as well because the LNG in the storage tank must be warmed up to return to a gaseous state for receipt

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[30] The BTU value refers to the number of BTU per cubic foot of natural gas, i.e., the heat content per unit of volume, or BTU/cf. The BTU value varies within a wide range of 950 to 1150 BTU/cf at standard temperatures and pressure of dry gas (60 degrees Fahrenheit and 14.73 psi). https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html The range is wide due to variation sin the BTU content of production from different basins across the U.S. The typical heating value for Utah is reported by the EIA as 1042 BTU/cf. https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm

into the distribution system at the appropriate pressure. In both stages, liquefaction and withdrawal, the fuel loss (heat loss + fuel use) can be expressed as a percentage of the amount of gas to be ultimately delivered on withdrawal, similar to the way that LDCs represent their systemwide fuel rate in their tariff for customers that elect to purchase third party gas supply. For example, if the LDC requires 1,000 Dth of gas supply from the LNG facility to meet demand on a given day, and the overall fuel loss percentage across all three stages, liquefaction, storage and withdrawal, is five percent, then 1,050 Dth must be scheduled for receipt at the inlet to the LNG facility (i.e., 1,000 times 1.05 equals 1,050 Dth).

Q: Besides its contribution to fuel loss, do you have another reason to discuss ambient conditions in your testimony?

A: Yes, I do. At the June 19, 2018 technical conference, which I attended by conference call, DEU representatives were asked by the Commission if ambient temperature had an effect on the cost of producing LNG. Representatives of DEU explained that the process was an enclosed system and, therefore, ambient temperature would have no effect on the production of LNG.[31] Subsequent to the technical conference, the Commission issued an Action Request asking the Division to "investigate some of the industry and academic research into the impact of ambient temperature on the LNG liquefaction process."[32]

Q: What is your understanding of the Commission's concern with ambient temperature?

A: Basically, my understanding of the Commission's concern with the Proposed LNG Facility is whether variations in ambient temperature conditions are a reference to how the ambient temperature and pressure conditions at various geographic locations may

[31] I am informed by Division Staff that the question and answer can be heard on the "Audio of Technical Conference Presentation held June 19, 2018," found on the Commission's website under this docket, at minute 4:00 through 4:50.
[32] Commission Action Request, "Dominion Energy Utah's Request for Approval of a Voluntary Resource Decision to Construct a Liquefied Natural Gas Facility, Docket No. 18-057-03," June 19, 2018.

increase the operating costs of an LNG facility located in Utah. In order to assist the Staff with this Action Request, I discuss ambient conditions in my testimony based on my experience and my review of publicly available literature obtained from an internet search. Two articles seemed particularly relevant to the Commission's Action Request, which I summarize below.

Q: What do the results of the two articles you selected based on your literature research reveal about ambient conditions?

A: The first article evaluates the impact that ambient temperature has on the performance of various natural gas liquefaction processes around the world. This article concludes that "the energy consumption of any optimized gas liquefaction process will be 20–26% higher in the Middle East or Northern Australia than in an Arctic climate such as that found in Northern Norway."[33] However, I would point out that this higher energy consumption in the Middle East may be referring to large scale LNG facilities located in the Middle East that participate in worldwide LNG export trade. Therefore, while I observe that the location of the Proposed LNG Facility in Utah would not have ambient conditions similar to Norway and would not be built to the scale of a major export facility such as those engaged in world LNG trade, I use the magnitude of the increase in energy consumption in the Middle East as a sensitivity in my review of the second article, as discussed below.

Q: What does the second article from your literature search tell you about LNG refrigeration efficiency?

A: The second article is focused on variation in energy efficiency of different refrigeration

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[33] DPU Exhibit 2.4, Abstract "Impact of Ambient Temperature on LNG Liquefaction Process Performance: Energy Efficiency and CO2 Emissions in Cold Climates", Steve Jackson* , Oddmar Eiksund, and Eivind Brodal, UiT-The Arctic University of Norway, Tromsø 9037, Norway, Ind. Eng. Chem. Res., 2017, 56 (12), pp 3388–3398, DOI: 10.1021/acs.iecr.7b00333, Publication Date (Web): March 8, 2017, Copyright © 2017 American Chemical Society, https://pubs.acs.org/doi/pdfplus/10.1021/acs.iecr.7b00333

technologies typically used for smaller scale LNG facilities that are closer in scale to the Proposed LNG Facility than those considered in the first article:

> "At first glance, there are numerous process alternatives on the market. However, when taking a closer look, the choice simplifies to either single mixed refrigerant ((SMR) or nitrogen expander technology. These technologies dominate the small-scale plant capacity range between about 50,000 and 500,000 gallons of LNG per day."[34]

This second article confirms that power consumption of any refrigeration process increases with rising ambient temperature, as illustrated in the chart below for a given pressure (40 bar).[35]

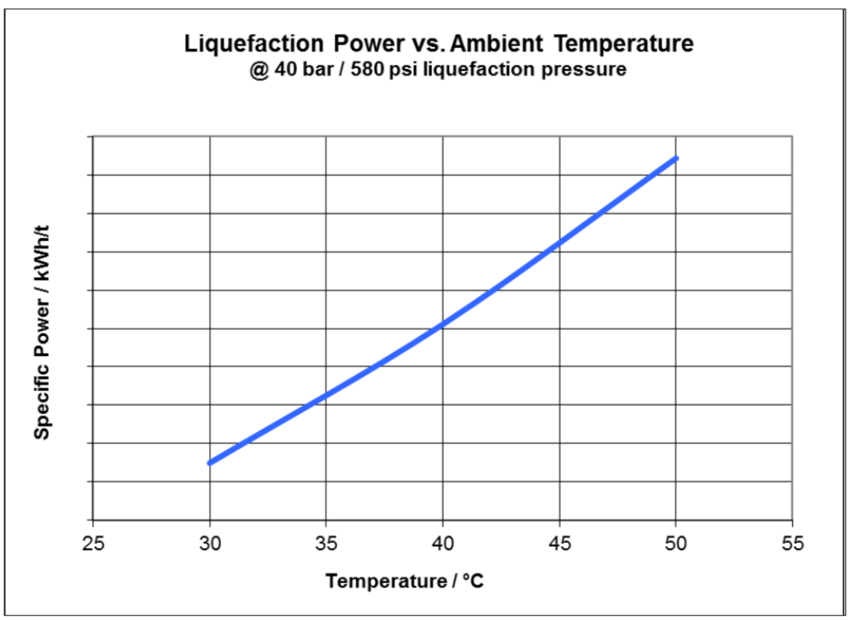


Figure 3 Liquefaction Power vs. Ambient Design Temperature

[34] DPU Exhibit 2.5, "Small-scale LNG – what refrigeration technology is the best?" T Kohler & M Bruentrup, Linde Engineering, R D Key & T Edvardsson, Linde Process Plants, Digital Refining, March 2014, page 1. http://www.digitalrefining.com/article/1000909,Small_scale_LNG_____what_refrigeration_technology_is_the_best_.html#.W2XjwyhKguU

[35] Ibid, page 2.

The article also says that within this range of power consumption, these two technologies – also evaluated for the Proposed LNG Facility – differ. But, while one refrigerant technology may be more efficient, the savings in power costs is offset by higher capital costs, with a total cost difference of 1% and 5% between the two.[36]

Q: How would you apply what you learned from your review of the literature to your review of the Filing?

A: I would consider the range of 20% to 26% increase in energy consumption for LNG plants located in the Middle East versus a cold climate such as Norway helpful to consider as a sensitivity. First, plants located in the Middle East are large scale baseload plants, not the smaller scale Proposed LNG Facility intended to provide peaking service. Second, when applying the upper bound of the delta in energy consumption to the smaller-scale LNG facility as a sensitivity, I would apply it to the baseline fuel loss inherent in the facility design. That is, I would increase the design fuel loss by the increase in this first study, not replace it with this higher percentage, as I discuss in my example below.

Q: How much would ambient conditions have to increase in order to have a significant impact on fuel loss during the liquefaction phase?

A: As I described above, the storage facility is insulated and maintained under minimal pressure to minimize boil off gas. During the liquefaction process I described above, gas supply is exposed to ambient conditions because it needs to be first warmed up and then cooled. The amount of fuel loss during this stage is determined by a combination of the magnitude of change – let's call it a "step-change" -- in ambient conditions, the total amount of gas supply, and the time duration of exposure. My understanding is that for an LDC-scale LNG facility, the time duration of exposure is relatively short. And even if

[36] Ibid, Section 4, Economics, which also mentions that the operating and capital costs are for "a typical LNG liquefier in a U.S. gulf coast location with a capacity of 200,000 gallons per day", page 7.

we assumed a thirty percent (30%) increase in fuel loss as a step-change in ambient conditions, this would be a 30% increase over the 5% fuel loss rate I hypothesized above as the baseline operating conditions of an LNG facility, which would result in an adjusted fuel loss rate of 6.5% (i.e., 0.05 times 1.30 = 0.065). So even for a significant step-change in ambient conditions, the impact on fuel loss across the facility production process could be considered *de minimis*.

Q: How do you know that your assumption of a 5% fuel loss rate as a baseline operation condition for an LNG plant is appropriate?

A: I used a 5% fuel loss rate for the baseline operating conditions of an on-system LNG facility in my arithmetic example above for illustration purposes only. However, I conducted an informal benchmarking exercise of my assumption by comparing it to two publicly available fuel loss rates:

i. DEU's fuel loss rate for Transportation customers of 1.5%, as published in its current effective Utah tariff, as shown in Exhibit 2.nn.[37]

ii. The fuel loss rate for an existing LNG facility interconnected to and operated by Northwest Pipeline, called the Plymouth LNG Facility, whose fuel retention rate for both liquefaction and withdrawal is published in the tariff schedule for LS service as 0.53% -- or less than 1%, as shown in Exhibit 2.nn.[38]

Q: How do you know that the baseline operation condition for the Proposed LNG Facility will be within the benchmark range you have assumed?

A: At this time, I do not have confirmation of what the Company has assumed as a fuel loss

[37] DPU Exhibit 2.6, Dominion Energy Utah, Utah Natural Gas Tariff, PSCU 500, Effective June 1, 2017, Fuel Reimbursement, page 5-2, https://pscdocs.utah.gov/gas/17docs/17057T02/293974PropTariffSheet5-12-2017.pdf

[38] DPU Exhibit 2.7 Northwest Pipeline, LLC FERC Gas Tariff, Fifth Revised Volume No. 1, Twenty-First Revised Sheet No. 14, Statement of Fuel Use Requirements Factors for Reimbursement of Fuel Use, Rate Schedules LS-2F, http://northwest.williams.com/NWP_Portal/extLoc.action?Loc=FilesNorthwesttariff&File=tariff_StatementofRates.pdf

percentage for the design of its Proposed LNG Facility. I have asked the Company for this information in discovery and await its response.[39] Once I receive and evaluate their response, I will review my testimony on this matter for potential revisions.

Q: In your opinion, does the occurrence of fuel loss due to exposure to ambient conditions mean that LNG is unsuitable for DEU as a supply resource?

A. No, because LNG facilities can be designed to reduce boil off through the use of insulation in the double-hull construction described above that minimizes heat ingress. However, my opinion is predicated on the assumption that the Company will require the overall design of the facility to minimize fuel loss during the liquefaction stage, as well.[40] This means that facility design can and should be tailored to accommodate the specific ambient temperature and pressure for the location chosen for the Proposed LNG Facility. This is necessary not only for operational reasons but also for economic reasons because it minimizes lost and unaccounted-for gas that the Company may request to be recovered through rates.

Therefore, so long as the Company can demonstrate that the design it has selected for the Proposed LNG Facility is consistent with industry standards for best in class gas utility LNG facilities at this location, and its operation and maintenance plan for the facility will not increase fuel loss over time, then I do not find this particular feature alone to be an impediment to considering an on-system LNG plant as a resource alternative.

VIII. IMPORTANCE OF NETWORK ANALYSIS AND DEU MODEL REVIEW

Q. How does the use of network analysis inform the decision before this Commission?

[39] DEU Response to DPU 8.1 (a) and 8.3 (not yet received).

[40] DEU Response to DPU 1.15, 6/22/2018, “The hydrocarbon liquids extracted during the LNG liquefaction process will either be re-vaporized and used on-site as fuel gas or will be collected in a tank for off-site disposal.”

A. The Company has petitioned for approval to construct the first storage resource that will be directly connected to DEU's distribution system.[41] Since the Proposed LNG Facility doesn't exist yet and is designed to address a hypothetical supply deficiency scenario that mimics the magnitude of supply deficiency events that occurred in the past, the best way to evaluate how well it does this is in a modeling environment.[42] For the gas industry, the typical robust modeling environment used for this purpose is a network analysis model, such as the Synergi system used by DEU and many other utilities.

Q. Please describe the purpose and benefit of Network Analysis.

A. Network Analysis allows the system planner to see the effect load growth has on the system over time. As new load is added to the distribution system, pressures drop. When those pressure drops become too severe, the remedy could be larger pipes, system looping and/or pressure regulation. Network Analysis tools allow a system planner to optimize the length and diameter of the pipe that needs to be installed to remedy the peak day low pressure issues. Just as the Company arrays gas supplies to meet the peak day distribution system needs, the system itself must be designed to deliver those supplies to the customer.

Q. How does Network Analysis optimize the configuration of the Company's distribution system?

A. The Company's distribution system configuration is made up of a combination of large diameter mains, operating at a relatively high pressure, and narrower diameter distribution pipelines, operating at a lower pressure, that ultimately deliver gas supply to individual service lines connected to homes and businesses. The volume of gas that can be delivered over a given segment, subsystem or the system as a whole is a function of

[41] Supply Reliability Technical Conference, June 19, 2018 presentation, slide 23.
[42] As stated above, one of the purposes of my testimony is to respond to the Division's request to evaluate the accuracy of the models that DEU used to support this Filing, which includes the model I describe in this section of my testimony.

interior pipe diameter and pressure. And the direction of gas flow can vary by main versus distribution segments and where these segments are located in relation to citygate interconnections. Network Analysis allows the system planner to show the effect on distribution pressure systemwide from the addition of a new source of deliverable gas either from citygate interconnections, or the location of the new on-system supply source proposed in this Filing. The model then reports a measurement of the change in systemwide pressure based on the configuration of the utility's mains and distribution facilities and the change in the amount and location of customer demand over time, including intraday and for the peak hour.

Q. Did you evaluate the Company's Network Analysis model as part of your review in this Filing?

A. Yes, I did. I was given the opportunity to observe the impact of a hypothesized on-system resource addition in a specific location on the Company's distribution system – as modeled in Synergi – under two different scenarios. Each of these scenarios captured the effect on systemwide distribution system pressure from a hypothesized supply loss: an upstream supply source failure and an interstate pipeline delivery disruption. I remotely viewed the model being run both before and after the addition of a source of supply at the location for the Proposed LNG Facility and observed the model's confirmation that an incremental 150,000 Dth/day of supply was received and systemwide pressures were restored to the appropriate levels. The results of the webinar modeling exercise are summarized in the Field Data Request response provided as FDR 1.01 Attachment 1, Summary of Shortfall Scenarios, July 11, 2018.[43]

Q. What do you conclude about the benefit of Network Analysis in this Filing?

A. I conclude that Network Analysis is an important step in the evaluation of whether the Company's Proposed LNG Facility is in the public interest. This is because Network

[43] FDR 1.01 Attachment 1, Summary of Shortfall Scenarios, July 11, 2018, see Wyoming Freeze-Off Scenario, Figure 4, page 3, and Opal Malfunction Scenario, Figure 8, page 5.

Analysis can show whether the Proposed LNG Facility's design could solve the peak day reliability problem. The Company's network model showed that a resource delivering gas supply at a high delivery pressure added at a critical location on the distribution system will raise pressures elsewhere on the existing distribution system on high demand days. However, Network Analysis by itself is not sufficient to determine whether the Proposed LNG Facility is in the public interest. As I describe in more detail below, it is also imperative that the Company show that it has fully evaluated all other cost-effective alternatives that can provide similar non-cost benefits of improved reliability.

IX. ALTERNATIVES CONSIDERED BY THE COMPANY.

Q. What alternatives did the Company consider in its filing?

A. Yes, the Company evaluated or partially evaluated several different types of alternative solutions that could fully or partially meet the 150,000 Dth/d shortfall. These options included renegotiating existing contract resource options, pursuing demand response programs for large end-users (who agree to switch to oil or curtail usage of natural gas) and residential customers (who adopt long-lived conservation measures), negotiate new contracts for underground storage service (five existing storage facilities, plus 4 service options for the yet to be constructed Magnum Energy Storage facility.) The cost estimates (if any provided) and non-cost criteria assigned to each of these options is summarized in DEU Exhibit 2.11, page 1.

Q. Did you consider all of these options for your review of this Filing?

A. I focused my attention on the underground storage options with particular attention on the yet to be constructed Magnum Energy Storage option, for reasons explained below, and I briefly considered the other non-storage options.

Q. Why did you only briefly review the non-storage options?

A. I assume that the Company will always look at renegotiating existing contracts, because that is something that gas utility management is expected to do during the normal course of carrying out their business responsibilities to shareholders and customers, including as part of recurring cost of gas filings. I acknowledge that some peak-sharing opportunities may exist among large end-users, but these would have to be limited to those with on-site alternate fuel and I have heard of electric generators refusing to switch to oil if the economics don't work for them, even if they have signed a peak sharing agreement with the LDC. Finally, I do understand that it may be difficult to obtain the full 150,000 Dth/d of supply by 2022 from residential demand response, and this would ignore any potential for on-system net growth in residential customers.

Q. Based on your review of the Filing, and DEU Exhibit 2.11 are there alternatives that the Company did not sufficiently evaluate in your opinion?

A. Yes, in my opinion, the Company should have evaluated two options in greater detail to provide the minimum level of support to allow a conclusion that their Proposed LNG Facility is the best option. These two projects are

- the Magnum Energy Storage option and
- the Intermountain Power Project (IPP).

I provide a brief summary of each of these projects below.

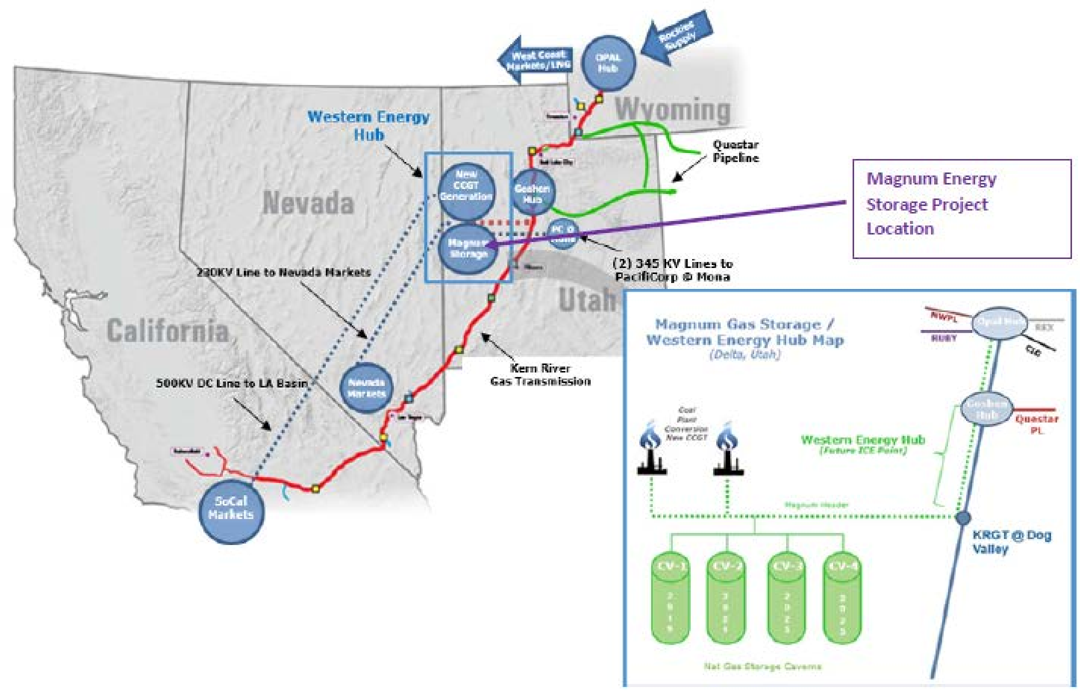
- **Magnum Energy Storage Project**

Q. Please briefly describe the Magnum Energy Storage project.

A. Magnum Energy Storage (MES) is a salt-cavern-based natural gas storage facility currently under development at a site near Delta Utah, as shown in Exhibit 2.8 below.

Exhibit 2.8 Map of Magnum Energy Storage potential market and schematic.

DPU Exhibit 2.8 Magnum Gas Storage Project, regional map and schematic



https://magnumdev.com/wp-content/uploads/2018/06/natural-gas-midstream-2.jpg

The developers plan to build a greenfield header pipeline to Kern River Gas Transmission and Questar Pipeline at Goshen, Utah. Once in operation, the developers suggest that the location of MES will offer backhaul and/or displacement capabilities on Kern River near Goshen and as well as other pipelines (Northwest Pipeline GP, Rockies Express Pipeline LLC, Questar Overthrust Pipeline Company, Colorado Interstate Gas Company, and Ruby Pipeline LLC) in the Opal, Wyoming, area. Initial plans call for the development of two salt caverns through solution mining ("Phase I") for an approximate total working gas capacity of 20,000,000 dekatherms ("Dth"). Each natural gas storage cavern will have working gas capacity of approximately 10,000,000 Dth. MGS has FERC approval for expansion capabilities to develop an additional two caverns (total of four), each with 10,000,000 Dth of firm working gas capacity (“Phase II”). Project potential (Phase I & II) may provide up to 40,000,000 Dth of working gas capacity. [44]

Salt cavern storage facilities offer the potential for flexible high deliverability service that, when compared to traditional underground storage projects, is well suited to meet short term increases in customer demand.

MES has submitted its pro-forma market-based rate tariff to FERC that includes firm and interruptible storage services, including hourly balancing and no-notice service under FERC docket number CP10-22-000.[45]

Q. Please summarize the service options Magnum Energy Storage offered DEU.

A. The Company explored four options for entering into a storage contract with Magnum Energy (Magnum).[46] While there are key differences among these options, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[47] In order for this option to be viable, approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[48] And DEU would need to construct a new interconnect facility to receive this gas into this distribution system at an estimated cost of

[44] DPU Exhibit 2.8, Magnum Natural Gas Midstream Storage Project Map, Schematic and Overview, https://magnumdev.com/project-information/magnum-gas-storage/
[45] FERC website Documents and Filings, Advanced Search, https://elibrary.ferc.gov/idmws/search/advResults.asp
[46] These four options, 3A, 3B, 3C and 3D, are summarized in DEU Highly Confidential Exhibit 2.11, page 1 of 32.
[47] Highly Confidential DEU Exhibit 2.0, Direct Testimony of Tina M. Faust, page 20, lines 459-461
[48] Confidential DEU Exhibit 2.11, page 13

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL],[49] which included gas transportation to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[50]

Q. What non-cost criteria did the Company consider when evaluating the Magnum Storage project?

A. The Company noted that salt cavern storage offers non-cost *benefits* in the form of being a proven safe and reliable method of storing gas that may be able to service a portion of the Company's peak-hour demand. However, Magnum does not meet the non-cost criteria of offering supply diversity because it is controlled by a third party. In particular, the Company raised four non-cost issues with this option[51]:

i. Magnum is not currently serving any natural gas storage customers, allowing the Company to conclude that Magnum's reliability is unknown at this time.

ii. The Company has also voiced concerns regarding the fact that this service is only available for five contiguous days during the heating season;

iii. Magnum Energy has not yet constructed or operated a natural gas storage facility or FERC regulated pipeline; and

iv. Magnum appears to offer less flexible service compared to an on-system facility due to reliance upon interstate pipeline delivery and FERC regulated scheduling deadlines that would limit intra-day availability, because [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL][52], access to this resource would still be controlled by a third party that would determine the

[49] Confidential DEU Exhibit 2.11, page 19
[50] Confidential DEU Exhibit 2.11, pages 12-19, and DEU Exhibit 2.0, page 19, line 457
[51] Confidential DEU Exhibit 2.11, pages 19-20
[52] Highly Confidential DEU Exhibit 2.11, page 1.

maximum quantity of service it could offer, presumably under a tariff service generally available to similarly situated customers – i.e., regulated utilities.

As a result, the Company justifies rejecting Magnum because, like all DEU storage options that are controlled, maintained, owned, operated, and delivered by a third party, it does not satisfy the non-cost criteria of increasing supply diversity on the DEU system.

Q. Are there any apparent physical infrastructure supply plan challenges that exist with this option?

A. Yes. Magnum's salt cavern facility is roughly 100 miles from the DEU demand center. DEU would need to make substantial facility additions along with paying for the storage service. The Company estimates that interconnect facilities at [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[53]

Q. How did the Company evaluate the difference between owning an on-system facility over contracting with an outside entity such as Magnum?

A. The Company rejected the alternative of contracting with Magnum over the Proposed LNG Facility for two main reasons:

First, the cost stream for the Proposed LNG Facility, after the initial investment, will be limited to maintenance and operation costs. By contrast, the cost-of-service rate structure under a third-party option such as Magnum would be subject to change over time, possibly even exceeding originally anticipated rates.[54]

Second, by comparison to third party storage,

[53] Confidential DEU Exhibit 2,0, page 20, lines 468-470.
[54] Confidential DEU Exhibit 2.11, page 19

a) the design and maintenance of an on-system storage facility would be within DEU's control;
b) DEU could design and build the facility to include redundancy on all critical equipment;[55] and
c) the Company would be in a position to control scheduling to ensure that foreseeable maintenance occurs outside the most critical times.

Q. Has Magnum subsequently offered to build a pipeline that would be dedicated to delivering incremental gas supply to a point near DEU's load center?

A. Yes, Magnum issued a non-binding Open Season for pipeline capacity on June 28, 2018, which is expected to close on August 31st of this year. However, the Company indicates that it is aware the Magnum Energy recently offered a non-binding open season but did not participate in it, although it participated in other Open Seasons events The Company said it is in communication with representatives from Magnum Energy on a regular basis and does not plan to submit a bid for additional transportation capacity as the current level of subscribed capacity is already adequate to meet the demand.[56]

Q. Do you find that the evaluation of the options available from Magnum Energy Storage is sufficient to support the Company's conclusion that the Proposed LNG Facility is a better alternative?

A. No, based on my review of the Filing and responses to discovery, I find that the Company has not sufficiently investigated and documented the Magnum Energy Storage alternative for the following reasons:

i. As no decision has been made on the suitability of a LNG facility, the decision not to participate in Magnum's open season is concerning. The Company must demonstrate whether Magnum's offering is competitive or not.

[55] DEU Exhibit 5.0, page 5, lines 136-138
[56] DEU response to DPU 6.3(b) and Confidential DEU Response to DPU 7-4.

ii. Further, if the proposals for terms of service discussed to-date have not been sufficient to meet the peak day deficiency, the Company has not documented whether they pursued negotiations further to obtain better terms and at what cost, so this option could be compared to the Proposed LNG Facility on both a cost and non-cost basis. For example,

a. The Company appears to have ignored the ability for Magnum Energy Storage to enhance reliability by delivering gas supply in the opposite direction of flow on Kern River pipeline that could improve deliverability and increase reliability; and

b. The Company has not explained how it evaluated the option to obtain an [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL][57]

iii. Finally, Magnum Energy's recent Open Season for pipeline capacity with delivery to the Salt Lake area suggests that the Company's Filing is premature until the results of this event – including any change in the Company's decision to participate in it – are known.

Q. What do you recommend that the Company do to evaluate the opportunity to obtain service from Magnum Energy Storage?

A. I recommend that the Company supplement this Filing, or make a new one, with information on its efforts to negotiate an agreement to provide service under terms that more closely match its peak day needs, including extended days of service and dedicated pipeline capacity to deliver gas supply directly into its distribution system. My understanding is that the Company recently issued RFPs for supply and upstream pipeline capacity, but the terms of service requested [BEGIN CONFIDENTIAL] [redacted]

[57] Highly Confidential DEU Exhibit 2.11, page 15 of 32.

[redacted] [END CONFIDENTIAL].[58]

Perhaps better, the Commission should require the Company to issue an RFP for the needed supply resources so that Magnum and other bidders may have an objective set of criteria against which to bid and against which the Company and the Division can evaluate the bids.

- **Intermountain Power Project**

Q. Please briefly describe the Intermountain Power Project.

A. The Intermountain Power Project (IPP) is an existing power generation facility located in Delta, Utah comprised of two coal-fired units with total installed capacity of 1,800 MW. IPP is owned and operated by the Intermountain Power Agency (IPA), a political subdivision of the State of Utah. IPA also owns, finances and maintains associated facilities, including the high voltage 2400 MW Southern Transmission System, extending from the IPP facility through Utah and Nevada and terminating in Southern California, through which it delivers IPPs generation to these 35 customers. An additional important fact is that IPP is located approximately 1.5 miles from the Magnum Energy Storage project discussed above.[59]

Q. Who are the utilities who receive power pursuant to IPP power sales contracts?

[58] Highly Confidential DEU Response to DPU 7.02 Attachments 1 through 10.
[59] FERC CP10-22-000, Order Granting and Denying Certificates, March 17, 2011, FN 83, page 30, https://www.ferc.gov/whats-new/comm-meet/2011/031711/C-4.pdf

A. IPP's 35 utility customers include 23 municipalities and 6 rural electric cooperatives in Utah and 6 municipalities in Southern California. The power sales contracts guarantee each utility a percentage entitlement share of the IPP total output of 1800 MW, with the Los Angeles Department of Water and Power (LADWP) maintaining an entitlement share of 48.617%.[60]

By the same token, these 35 utilities are also "unconditionally obligated to pay all costs of operation, maintenance and debt service, whether or not the Project or any part thereof is operating or operable, or its output is suspended, interrupted, interfered with, *reduced or terminated*." (italics added.)[61]

Q. What role does the IPP play in your review of this Filing?

A. IPP is relevant to this Filing because IPA and its utility purchasers have agreed to fund a plan to convert this coal-fired generation facility to natural gas in order to continue using IPP's generation and transmission capacity to sell power to its customers located in California once the term for the current power contract ends in 2027.[62] As I mentioned earlier, when I reviewed the Company's evaluation of alternatives to the Proposed LNG Facility, I expected to see consideration of off system storage projects. One of these projects, the Magnum Energy Storage project described earlier in my testimony, has been mentioned in industry publications as being a possible supplier to the IPP project once conversion to natural gas generation is completed by 2025.[63]

[60] DPU Exhibit 2.9 IPA website, Participants and Service Area, listing each municipal customer and their respective entitlements to a percentage share of IPP total generation. https://www.ipautah.com/participants-services-area/

[61] DPU Exhibit 2.10 IPA Financial Statements of and for the Years Ended June 30, 2017 and 2016, Supplemental Schedule for the Years Ended June 30, 2017 and 2016, and Independent Auditors' Report, Management's Discussion and Analysis, page 3, https://www.ipautah.com/wp-content/uploads/2017/09/IPA-Financial-Statements-FY2017-Final.pdf

[62] DPU Exhibit 2.11 LADWP 2017 Power Strategic Long-Term Resource Plan, Section 2.4.2.3. Coal-Fired Generation, pp. 109-110, https://www.ladwp.com/ladwp/faces/wcnav_externalId/a-p-doc?_adf.ctrl-state=rg1swdlf4_4&_afrLoop=346522907250975

[63] DPU Exhibit 2.12, Deseret News website, Delta-area salt caverns could store natural gas: https://www.deseretnews.com/article/705351952/Delta-area-salt-caverns-could-store-natural-gas.html;

Q. Why should the Company be interested in whether Magnum Energy Storage will serve IPP once it has converted to natural gas fired generation?

A. DEU should have been interested in whether Magnum Energy Storage plans to build, own and operate a pipeline that would terminate in the Salt Lake area, suggesting it could also serve IPP, because it may provide an alternative to the Company's own estimate of cost to acquire incremental firm capacity on Kern River Pipeline, as it assumed would be required under DEU Exhibit 2.11. This pipeline would provide access to the benefits of salt cavern storage offered by Magnum Energy, as described above, at a similar or possibly even lower cost than pursuing expansion capacity on Kern River.

Q. Has Magnum Energy Storage formally announced plans to construct such a pipeline?

A. Yes, on June 28, 2018 Magnum Energy Midstream Holdings LLC (MEM) announced a non-binding open season for interested parties to bid on capacity in a 650-mile pipeline that would serve multiple western states, including Utah where Magnum Energy Storage (an affiliate of MEM) is located. The Open Season for the Western Energy Storage and Transportation Header Project (WESTHP) commenced on July 2, 2018 and will close on August 31, 2018.[64]

Q. Has DEU confirmed whether it has or plans to participate in this open season for WESTHP capacity?

A. In my review of the Filing, I did not find confirmation that DEU evaluated participation in such an open season for a MEM pipeline project. Alternatively, DEU could have issued an RFP for a resource to meet the need to be addressed by the Proposed LNG

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it can reasonably be inferred that the proposed Intermountain Power Plant (IPP) Repowering project will or could be supplied by a 1.5-mile dedicated lateral from the proposed Magnum Energy Storage facility.

[64] DPU Exhibit 2.13, PR Newswire, Magnum Energy Midstream Holdings Announces Non-Binding Open Season For Natural Gas Storage And Transportation Header Pipeline In Western U.S., August 12, 2018.https://www.prnewswire.com/news-releases/magnum-energy-midstream-holdings-announces-non-binding-open-season-for-natural-gas-storage-and-transportation-header-pipeline-in-western-us-300673531.html

Facility to which MEM or Magnum Energy Storage could have responded with a proposal equivalent to the offering in the WESTHP open season. I did not find such information in this Filing. However, I have requested the Company to confirm participation in any MEM open seasons, and I have requested copies of any responses to RFPs the Company has issued to meet the identified need, which may yield a response from Magnum Energy Storage. Once I receive these responses, I will supplement my testimony accordingly.

Q. Why would securing a contract for capacity on a greenfield pipeline to be built by Magnum Energy Storage to serve IPP offer a potential savings to DEU?

A. While it is not known what rate Magnum Energy Storage will charge for its proposed WESTHP project, in my experience it is often the case that potential customers who agree to be the "anchor shippers" for such projects, i.e., who agree to minimum quantities of firm capacity for 10 to 20 year minimum contract terms, may be offered discounted rates as well as non-cost benefits such as flexible receipt and delivery points. Until more information is made available through responses to discovery, I cannot verify that the WESTHP project would offer such cost or non-cost benefits. However, I would have expected DEU to have pursued this line of inquiry and included what they learned as part of their review of alternatives.

Q. Do you see any concerns with MEM as an alternative to the Proposed LNG Facility?

A. I recognize that the Company has indicated that Magnum Energy Storage brings with it the same concern of being a contract resource that is subject to interruption due to force majeure, and the MEM project requires significant commitment on the part of many potential customers to go forward and enter service by 2025 – potentially up to three years after the in-service date of the Proposed LNG Facility.

However, while I feel that full analysis of the Magnum Energy Storage option is obvious by omission in the Filing, I can identify other concerns with the WESTHP alternative that should be considered.

Q. Please explain your concerns with the WESTHP project.

A. In order to understand the Magnum Energy Storage project as an alternative in the context of the potential advantage offered by WESTHP capacity, I have looked into the original power sales contract that governs the 35 utilities' obligation to purchase power from IPP, which terminate in 2027. I learned that further contract changes are being contemplated that may reduce or replace natural gas fired generation at IPP with renewable generation that could put the status of WESTHP in question.[65]

Q. What are the additional contract changes being contemplated for IPP customers?

A. As previously agreed to by the 35 utilities, in recognition that LADWP and the other California municipalities must reduce their purchases of coal-fired generation to meet California's and LADWP's renewable energy goals,[66] these utilities entered into Renewal contracts with IPP for continued rights to generation output from the planned converted o natural gas fired units as well as transmission rights (the "Renewal Power Sale Contract") that will commence upon termination of the original power contract.[67]

[65] DPU Exhibit 2.14 Intermountain Power Project will shutter coal-fired power plant near Delta by 2025 due to losing its Southern California customer base." Deseret News, May 23, 2017. https://www.deseretnews.com/article/865680637/Intermountain-Power-Project-will-shutter-coal-fired-power-plant-near-Delta.html

[66] DPU Exhibit 2.15 LADWP News Alert, May 31, 2018, LADWP has committed to "a minimum of 65% renewable energy by 2036" and "to stop using coal power by 2025, two years earlier than required by California legislation (SB 1368)" LADWP news alert, http://www.ladwpnews.com/information-regarding-proposal-to-reduce-fossil-fuel-generation-at-intermountain-power-project/.

[67] DPU Exhibit 2.10 IPA Financial Statements of and for the Years Ended June 30, 2017 and 2016, Supplemental Schedule for the Years Ended June 30, 2017 and 2016, and Independent Auditors' Report, Section 10. Power Sales and Power Purchase Contracts, page 23, https://www.ipautah.com/wp-content/uploads/2017/09/IPA-Financial-Statements-FY2017-Final.pdf

Subsequently, the original plan to convert from coal to an equivalent 1200 MW of gas-fired generation was scaled back to 840 MW (still two-units) to accommodate the delivery of more renewable generation on the IPA transmission line to Southern California, a reduction led by LADWP[68] and memorialized an amendment to the Renewal Power Sales Contracts on January 17, 2017 (the "Renewal Amendment") that includes a 50-year term.[69]

The plan for repowering IPP on natural gas remains in doubt, however, due to additional information obtained through research. I have also reviewed one of the documents being evaluated by one of the participating Utah municipal utilities, Hyrum City, identified as Resolution 18-13, which contemplated approval of an "Alternative Repowering" that accommodates changes to the contract without being put to a subsequent vote by the 35 utilities. This Resolution allowed for prior approval of changes that include:

> "… modified versions of or alternatives to the Gas Repowering to provide for one or more sources of electric generation in addition to or in substitution, *in whole or in part*, for the Gas Repowering may be determined to provide increased benefits or to be otherwise advantageous for the Project."[70] *(italics added.)*

Inclusion of such an Alternative Repowering amendment to the Renewal Amendment described above suggests that between now and when construction would begin on the

[68] DPU Exhibit 2.15, LADWP New Alert dated May 31, 2018, announced that LADWP led the campaign to gain the support of all 35 utilities to accept LADWP's recommendation to amend plan to repower the 1200 MW IPP, as previously approved pursuant to binding renewal contracts, to a scaled down to 840 MW, as stated in LADWP's 2017 Power Integrated Resource Plan, http://www.ladwpnews.com/information-regarding-proposal-to-reduce-fossil-fuel-generation-at-intermountain-power-project/.

[69] DPU Exhibit 2.10 IPA Financial Statements of and for the Years Ended June 30, 2017 and 2016, Supplemental Schedule for the Years Ended June 30, 2017 and 2016, and Independent Auditors' Report, Section 10. Power Sales and Power Purchase Contracts, p. 23 defines the Renewal Amendment, https://www.ipautah.com/wp-content/uploads/2017/09/IPA-Financial-Statements-FY2017-Final.pdf

[70] DPU Exhibit 2.16 Resolution 18-13, Approval of Alternative Repowering, between IPA and Hyrum City Corporation as "Municipality", undated and unsigned, pages 1-3, https://www.utah.gov/pmn/files/392007.pdf

new gas-fired units for IPP, the utilities could decide to further reduce the amount of gas-fired generation to make way for more renewable generation with access to the IPA transmission line, up to and including cancellation of gas fired conversion all together.

Were IPA to exercise its right contemplated in this Alternative Repowering amendment, and in a timely manner prior to any commitment to MEM, it could bear negatively on the proposed WESTHP project.

Q. What do you conclude with respect to this Amendment and the importance for DEU to conduct a full evaluation of Magnum Gas Storage as an alternative to the Proposed LNG Facility?

A. I conclude that the existence of the Alternative Repowering Amendment, if it has been memorialized in signed agreements by the 35 utilities, while bearing negatively on the project, may provide an opportunity for DEU. DEU might be able to obtain benefits as an anchor shipper on WESTHP, these benefits are unquantified at this time, and there is some risk to the project.

However, this does not relieve DEU of the obligation to provide a full analysis of the cost and non-cost benefits of contracting directly with Magnum Energy Storage to obtain a service tailored to its defined need and compare it to that offered by the Proposed LNG Facility. The need for such analysis would be mitigated if an RFP were utilized to discover options and costs, as I have recommended.

Q. Do you recommend that the Commission consider MEM's proposed WESTHP pipeline project to serve IPP as an alternative to be included in a supplemental filing by DEU?

A. No, I do not, for the reasons summarized above. In fact, I am concerned that the repowering of IPP will have the effect of DEU supporting electric utility strategic planning goals, when instead we should evaluate how pipeline capacity projects directly benefit gas ratepayers. However, it is one indication that various other options may exist in the market that DEU has not properly evaluated. Discovering these options is a major purpose of the recommended RFP.

- **Importance of Cost and Non-Cost Criteria:**

Q: What approach did the Company take in its Filing when presenting its evaluation of the potential options?

A: The Company's approach to option evaluation relied primarily on the testimony of two witnesses. Company Witness Mendenhall provided a summary of the estimated costs, which included use of a levelized revenue requirement to calculate annual cost and calculation of dollar and percent impacts to an average customer bills, of each potential option considered by the Company in DEU Highly Confidential Exhibit 1.05. Additionally, Company witness Tina Faust provide a summary table in DEU Highly Confidential Exhibit 2.11 that showed the Company's comparative analysis of each potential option in terms of safety, reliability, cost, risk, and other factors. Of course, only those options the Company chose to evaluate were considered, leaving open the possibility that other options, or permutations of chosen options, exist.

Q: What does the Company say about the cost and non-cost criteria used in its evaluation of the resource options considered?

A: In Redacted Exhibit 1.0, Witness Mendenhall, explains why the LNG storage facility is the best option provided when considering cost, safety, and reliability. Specifically, he states that:[71]

> While the cost of the proposed LNG facility is more than the cost of certain alternatives analyzed, when all other factors are weighed and analyzed, the on-system

[71] DEU Exhibit 1.0, pp. 8-9, lines 191-199.

LNG storage facility is the best option. While the LNG facility is more costly than certain of the alternatives considered, it is by far the best option in terms of reliability, system flexibility, and risk-minimization. As other witnesses will explain further, if the Company selected one of those lower-cost options, it would be accepting an alternative that did not adequately solve the supply reliability issues or address the other factors and concerns facing the Company and its customers. Those options are also short-term options at best and don't solve the problem in the long term.

The Company explains that cost, or revenue requirement impact, is not the only deciding factor that should be considered when evaluating a resource option. While total cost may be the most important criterion from the aspect of ratepayers because it impacts their monthly bills, the statute requires the Commission to consider other equally important non-cost criteria (i.e. safety and reliability).

Q: How important are cost and non-cost criteria in the evaluation of resource options the Company considered?

A: In any benefit-cost analysis, there are always quantifiable and non-quantifiable costs and benefits. While costs can usually be reasonably assigned,[72] the benefits tend to be more qualitative. When considering which resource option is best for the Company's portfolio, it is important for the Company and the Commission to consider non-cost criteria that can either add value or create risk. As mentioned above, the Company has stressed that the appropriate non-cost criteria are safety and reliability. Another non-cost criteria that is often associated with on-system LNG facilities is flexibility. DEU also mentions that it values the diversity that an on-system LNG facility brings, which could also be considered a non-cost criterion.[73]

Q: Are there pros and cons to evaluating potential resource options on both cost and non-cost criteria?

[72] The reasonableness of costs is usually debated, especially when contractor and market price estimates are used.
[73] Redacted DEU Exhibit 2.0 Direct Testimony of Tina M. Faust, page 19, line 496,

A: Yes, there are. First, it is important to evaluate potential resource options on cost criteria because that is ultimately the price that ratepayers will be allocated to pay. If this was the only criterion though, the evaluation would be lacking other important impacts of each potential resource option. For example, reliability of the resource option to serve customers during a peak day or severe weather event. Additionally, the total cost may not have captured all the risk associated with the resource option in delivering when requested. On page one of Tina Faust's Confidential Exhibit 2.11, she provides a list of other factors that were considered by the Company. These other factors include timing, operations, obligation to serve firm customers, peak-hour supply, availability, and other ancillary benefits. These are all important considerations in which value is not easily assigned.

However, while it is important to consider the non-cost criteria that the Company has identified, it is equally important to not over-analyze the potential impacts of non-cost criteria. Focus should be placed on the highest impact criteria related to the Company's system. Rightly, the Company has focused on safety, risk and reliability. All of these are not just important to the Company's system, but also directly impact the Company's customers.

Q: Has the Company properly evaluated the cost and non-cost criteria for each resource option?

A: No. Based on my review of the Filing and responses to discovery (forthcoming -RFP), it appears that the Company has failed to provide a thorough apples-to-apples analysis of the potential resource options compared to the LNG storage facility. While it is true that the LNG storage facility addresses the Company's needs on a peak day and for supply reliability, I believe that some of the other potential resource options may equally address the Company's needs.

For example, the Company raises the concern that supply delivered via third party pipelines can be disrupted by the pipeline operator due to maintenance or operation upset. The Company identifies the risk associated with pipeline capacity as associated with

[BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL][74] Yet, the Company acknowledges that it has been able to manage recent supply disruption by purchasing additional supplies and utilizing available storage, which presumably were delivered via pipelines.[75] In other words, the Company can't argue that the Proposed LNG Facility is the best solution to their reliability concerns on the one hand, and then report that pipeline capacity has successfully resolved supply disruption events on the other hand.

As a result, to evaluate if these other potential resources would be better options for the Company, I would require more information from the option bidders. This is yet another reason why the Commission should order the Company to file an RFP to meet the needed capability: to allow fuller exploration of the market, discover prices, and provide a single platform on which to evaluate all options.

- **Satellite LNG Facilities Ancillary Benefit as Support for this Filing**

Q: You mentioned that the Company evaluated the potential resource options on cost and non-cost criteria. Do you have additional concerns regarding any of the criteria the Company used in evaluation of the potential resource options?

A: Yes. I am concerned that the Company appears to include a description of the potential for *ancillary* benefits of the LNG storage facility as a kind of non-price criteria.

Q. Please briefly describe a Satellite LNG facility in the context of this Filing.

A. A Satellite LNG Facility is best described as a smaller scale version of the Proposed LNG

[74] Highly Confidential DEU Exhibit 2.0, Direct Testimony of Tina M. Faust, page 18, lines 435-439.
[75] Redacted DEU Exhibit 2.0, Direct Testimony of Tina M. Faust, page 5 at 106-107.

Facility except that it typically does not include a liquefaction unit. Instead it is comprised of a smaller above ground storage container (often called a “bullet” to denote its smaller size and shape) and a vaporization module that re-gasifies the stored LNG for delivery into the distribution system. Thus, while it still provides similar flexibility in the form of intra-day dispatch, it is dependent on delivery of inventory in the form of trucked LNG, delivered in a manner to meet daily and seasonal demand. A typical gas LDC Satellite LNG facility would have storage capacity ranging from 8,000 Dth up to 1 million Dth and withdrawal capacity (injected into the distribution system) ranging from 8,000 Dth/d up to 48,000 Dth/d.[76]

Q: What does the Company say about the ancillary benefits of the LNG storage facility?

A: In Confidential Exhibit 2.11, Witness Faust states that ancillary benefits of the LNG storage facility are that it “[p]rovides for the ability to serve outlying areas through the use of satellite storage facilities” and “[m]aintain service during emergencies or maintenance.”[77] Additionally, in her Direct Testimony, Ms. Faust explains that by the LNG storage facility could be utilized “to provide service to remote communities at a lower cost than extending pipeline facilities to these customers.”[78] During the Technical Conference held on June 19, 2018, the Company explained how the LNG storage facility could be used to serve the remote communities in Utah:[79]

- Satellite vaporization facilities could use trucked LNG to provide base load for their communities.
- After initial filling, the full liquefaction window would likely not be needed solely to fill the tank. Portions of the liquefaction window could be used to fill remote tanks.

[76] DPU Exhibit 2.17 Columbia Gas of Mass, Docket MA-DPU 15-143 2015 Forecast & Supply Plan, Table G-14 Existing On-System Peaking Resources, which is consistent with DEU Supply Reliability Technical Conference presentation, June 19, 2018, slide 5: Typical PHMSA Tank Sizes (Peak Shaver Facilities) Liquefaction and Vaporization rates for satellite facility are 8.2 MMcf/d and 10 MMcfd respectively.
[77] Confidential DEU Exhibit 2.11, p. 1.
[78] DEU Exhibit 2.0, p. 23, lines 543-544.
[79] Supply Reliability Technical Conference held 6/19/2018, slide 6.

- The current design of the plant does not include trucking terminals.
    - Additional liquefaction trains and trucking terminals could be added in the future.

Additionally, the Company provided more detailed information, including city, footage, pipeline extension, cost, peak daily load (MMcfd), and maximum annual load (MMcf).[80]

Q: Why are you concerned about the Company including these ancillary benefits in its non-cost criteria?

A: I am concerned about the Company's reference to satellite LNG facilities as an ancillary benefit for two reasons: 1) Any satellite LNG facilities that are discussed by the Company in this docket are only theoretical, as there is nothing officially planned, and this docket is specifically limited to the building of a single LNG storage facility sized to meet a design peak day deficit for existing demand. 2) The design of the Proposed LNG Facility requires 180 days to refill,[81] leaving few if any days when pipeline capacity and gas supply commodity would be available to liquefy gas supply for redelivery by truck to the satellite locations, suggesting that the design as currently proposed is not sufficient to provide the hypothesized ancillary services without additional capital investment. This is supported by the Company stating during the Technical Session (slide 6) that the current design of the plant does *not* include plans for serving remote communities. (italics added.)

Further, it is clear that the ability to serve these communities' winter load would require more days of liquefaction service than is available after the above mentioned 180 days required to fill the main facility is completed. Finally, even if the main facility could produce the required amount of LNG, the Company would have to schedule many truck deliveries to keep these satellite facilities full to meet winter load.

[80] Supply Reliability Technical Conference held 6/19/2018, slide 7.
[81] DPU 2.14 Attachment, page 5, 1st line of paragraph following Table 2.

Q: Why would it be a problem for the Company to have to schedule many truck deliveries to meet the winter load for the remote communities?

A: It is a problem because the Company has not provided a cost for the logistics required to serve these communities. While we do not have costs from the Company, we can infer from the Company's response to discovery that trucks are assumed to hold 9,000 gallons[82] and in total all four communities have a seasonal load of approximately 1,481,000 Mcf.[83] Converting 9,000 gallons to an equivalent 726 Mcf implies approximately 2,000 truck deliveries over a winter for all four communities to keep the satellite LNG storage tanks full and remote customers fully supplied. Since there are approximately 151 days in the winter period, this implies a trucking schedule of 13 trucks per day, including overnight assuming deliveries could be made around the clock.[84] The expense associated with supplying this service, including securing the truck fleet and obtaining local approvals is unknown at this time. This benefit should not be considered because it is too uncertain.

Q: What do you conclude from your review of the Company's claim to ancillary benefits associated with satellite LNG facilities in its Filing?

A: I find that:

i. it is not clear whether the Company will in fact experience the hypothesized growth in the identified communities,

ii. the stated need for the Proposed LNG Facility is to serve a deficiency to meet *current* demand in a specific area of the distribution system under peak day conditions, and

iii. the refill schedule for the Proposed LNG Facility as described in the Filing may

[82] DEU Response to DPU 6.10 (f).
[83] DEU Technical Session, June 19, 2018, slide 7, equals the sum of the column labeled "Max Annual Load MMcf".
[84] This calculation is supported in Exhibit DPU 2.0 Neale Workpaper_SatLNGTrucks.xlsx.

preclude servicing any satellite facilities, which would rely upon trucked LNG from the Proposed LNG Facility for refill through the winter.

Therefore, I find that service to remote communities should not be expressly provided as a non-cost criterion used in the evaluation of the Proposed LNG Facility in this docket.

Q. **What do you recommend for the evaluation of the ancillary benefit associated with the potential for satellite LNG facilities in this Filing?**

A. I conclude, based on my findings above, that service to remote communities yet to be interconnected to the Company's distribution system would have to be – and are more appropriately -- addressed in a future docket where the Company would have the ability to present multiple resource options to serve those communities. One of these could comprise alterations to the Proposed LNG Facility, should it be approved by the Commission in this docket. Therefore, service to remote communities should not be expressly provided as a non-cost criterion used in the evaluation of the Proposed LNG Facility.

- **Other Concerns**

Q. Please briefly describe your concern with potential for cross subsidization of the Transportation customer class by firm residential customers.

A. My concern is that the Company has stated in its filing, as described above, that it is trying to solve a potential supply shortfall on a Design Peak Day and even during extended extreme cold weather events that may not reach Design Peak Day temperatures and would be left with insufficient gas supply to serve firm customers. However, when making this statement, the Company does not identify whether the supply shortfall is due to Transportation customers' supply failure.[85] But if the Company's Proposed LNG Facility is intended to keep Transportation customers whole – directly or indirectly --

[85] See DEU response to DPU 4.01 and DPU 4.01 Attachment 1 showing confirming party reductions by day, nomination cycle and reason.

when the latter's third-party supply doesn't show up, then the Company should either:

- charge Transportation customers for this firm backup / balancing service under an appropriate rate design that assures cost recovery in a timely manner, or
- install appropriate facilities that allow the Company to shut-off Transportation customers who continue to take gas even though their supply has failed following a Company-issued curtailment order.

Q. Why should the Company pursue these tariff changes and how do you recommend they do so?

A. The Company should pursue these changes to its tariff – whether or not the Proposed LNG Facility is built – because to do otherwise risks cross-subsidization of Transportation customers by firm customers, which is not consistent with just and reasonable rates. If the Proposed LNG Facility is approved, I recommend that the Company conduct an allocated class cost of service study prior to its next rate case. I further recommend that, based on the results of that study, DEU should develop a Transportation customer tariff that provides for firm rates to receive back-up supply provided by the Proposed LNG Facility.

Q. Please briefly describe your concern with preserving the full benefit of the Proposed LNG Facility, in the event this Filing is approved by the Commission.

A. Having demonstrated the high value of having an on-system storage facility that could respond rapidly to changes in supply and/or demand, I am concerned that the it could be subject in the future to transfer of control to a non-regulated service affiliate in exchange for a service contract that substantially mimicked the physical delivery of daily and seasonal quantities but would be missing the intra-day control benefit. Aside from control issues, it would be inequitable to have ratepayers bear the risks of construction, financing, and the like, only to have an affiliate reap significant benefits from the facility.

I am also concerned that this Proposed LNG Facility could be used to make both on-system and off-system sales to non-firm customers and interstate pipelines (as a pressure support service) rather than being preserved to meet the non-cost criteria of maintaining reliable service for firm sales customers, as required under the burden of proof discussed above.

Q. Are you aware of any instance where such a transfer of control and service substitution has taken place?

A. No. However, I am aware of an attempt to do so that was unsuccessful. I participated as an expert witness in a case involving a request by NStar Gas to agree to a revised contract for service from the Hopkinton LNG facility, located in Hopkinton Massachusetts. The Company's request was denied, as can be seen in the final order in D.P.U. 14-64.

Q. Please briefly describe your concern with preserving the full benefit of the Proposed LNG Facility, in the event this Filing is approved by the Commission.

A. My recommendation would be to condition any approval of the Proposed LNG Facility -- in this Filing or any supplemental filing -- on a commitment by DEU to:

i. retain ownership and control of this asset and to prohibit transfer or sale of the facility or its capacity and deliverability to any third party without prior review and approval by the Commission; and

ii. affirmatively designate the facility as a material strategic resource asset under the terms of the recent Merger Agreement, as discussed in my findings above.

X. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions based on your review of the Filing.

A. Based on my review of the Filing and my findings summarized above, I offer the following conclusions:

1. The Company has shown that its network analysis model demonstrates that a

strategically located resource that provides the same delivery capacity as the Proposed LNG Facility will maintain minimum systemwide operating pressures under the design peak-day supply deficiency scenarios the Company's Gas Supply Planning Department has evaluated;

2. The Filing does not meet the burden of proof for the Proposed LNG Facility to be in the public interest because, although the Proposed LNG Facility will adequately address the stated need to provide a reliable and low-cost, it is not necessarily the lowest cost solution for firm customers;
3. To evaluate whether the Proposed LNG Facility or another option is in the public interest, the Company should be required to supplement its Filing, or make a new one, as described in my findings above and issue an RFP, which would allow better consideration of all appropriate alternatives;
4. The Company should be required to provide assurance that Proposed LNG Facility will remain under the control of the Company for the express benefit of firm sales customers and not be transferred to any affiliate of DEU.

Q. Please summarize your recommendations for the Commission

A. Based on my findings and conclusions discussed above, I respectfully suggest that the Commission do the following:

1. Find that the Filing does not meet the burden of proof, which requires a showing that it will result in service at the lowest reasonable cost to the retail customers. The Company's filing is insufficient because
   a) the Company has not shown that it has adequately analyzed the alternatives considered; and
   b) it relies on ancillary benefits of Satellite LNG facilities to serve future growth to support its claim that the Proposed LNG Facility is in the public interest;
2. Find that the Company's supporting network analysis model results confirm the ability of the Proposed LNG Facility to meet, for reliability planning purposes, a

supply shortfall of 100,000 Dth/day up to 150,000 Dth/d but is not sufficient by itself to meet the Burden of Proof requirement;

3. Require the Company to adequately consider all alternative options, even if these options do not offer to provide the full capacity required to meet the shortfall scenario for reliability planning purposes;
4. Require the Company to issue an RFP to meet the desired supply resources, which will allow adequate consideration of all options;
5. Require the Company to evaluate recovering an appropriate share of the cost of the Proposed LNG Facility from Transportation only customers based on a future allocated cost of service study to be conducted as part of the next rate case; and
6. Require the Company to designate the Proposed LNG Facility as a materially strategic resource under the provisions of the Merger Agreement approved in Docket 16-057-01 to assure that it will not transfer ownership and/or control of the proposed LNG Facility to any affiliate of DEU without prior review and approval by the Commission.

Q. Does this conclude your testimony?

A. Yes.