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**BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH**

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| 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 |

**Prefiled Surrebuttal Testimony and Exhibit of David J. Schultz on behalf of Magnum Energy Midstream Holdings, LLC**

Magnum Energy Midstream Holdings, LLC hereby files the Prefiled Surrebuttal Testimony and Exhibit of David J. Schultz in this docket.

DATED this 20th day of September 2018.

/s/ *Kevin B. Holder*___________

Kevin B. Holder
Executive Vice President
Magnum Energy Midstream Holdings, LLC

**Q. Please state your name and business address.**

A. My name is David Schultz. My business address is 35 Lake Mist Drive, Sugar Land, Texas 77479.

**Q**. **By whom are you employed and in what capacity?**

A. I am an independent consultant contracted by Magnum Energy Midstream Holdings, LLC regarding the Magnum storage and pipeline option designed to serve the needs of Dominion Energy Utah (DEU) for supply reliability and/or peaking services.

**Q. Please describe your educational background.**

A. I hold a Bachelors of Arts degree from the San Diego State University.

**Q. Please describe your professional experience and background.**

A More than 35 years of my professional career has been in the natural gas and power sectors. Prior to becoming an independent consultant, I was a one third owner of New World Global, LLC and New World Fuel, SA de CV, where I managed the acquisition, sale and logistical movement of hydrocarbon fuels from supply sources in the US and Canada to markets in Mexico. Before that I was Senior Vice President for LNG America where we sought to bring LNG as a fuel to marine and land based markets in the US. Prior to that I worked in various senior management roles at AGL Resources including the start-up of Pivotal LNG that focused on bringing LNG from the utility's LNG and merchant plants to terrestrial and marine uses. In that role, I was responsible for the operations of the Pivotal LNG's merchant LNG operations, sales and marketing, along with the planning, evaluation, and decision making regarding the design, possible construction and operations of proposed LNG facilities of a similar size to LDC peaking facilities. In that role, I became intimately familiar with the safety of such facilities, and their capital and operating cost. That understanding applies to both new and existing LNG facilities, utility owned and merchant. Prior to that role at AGL Resources, I developed AGL's 18 BCF of working gas capacity Golden Triangle Storage Project near Beaumont, Texas on the Spindletop Salt Dome. In that role, I became intimately familiar with the design and safety of underground storage facilities, including permitting, construction, capital cost and operating cost. Prior to that role at AGL I was responsible for the development of a nearly $3.0 billion LNG Import facility in Virginia. In addition, I have held other senior energy positions with Energy Transfer, Reliant, Duke Energy, Panhandle Eastern, PGT (a wholly owned subsidiary of PG&E) and San Diego Gas and Electric. I have spoken at over 50 industry conferences on a wide variety of topics including LNG and Natural Gas Storage projects and operations.

A copy of my curriculum vitae is attached as Magnum Exhibit 2.1SR.

**Q. What were you asked to do in this docket?**

A. I was asked by Magnum to review rebuttal testimony filed by Dominion Energy Utah ("DEU) in this docket that purports to compare and contrast the high-deliverability underground salt dome storage/pipeline project proposed by Mangum with the LNG storage facility proposed by DEU. Specifically, I will respond to rebuttal testimony of DEU witnesses Mr. Paskett, Mr. Gill, Mr. Mendenhall, and Ms. Faust regarding comparisons between storage and LNG facilities on various issues such as permitting, safety, value, obsolescence, complexity, operating costs, capital costs, flexibility, and industry preferences.

## **Executive Summary**

**Q. Can you provide a brief summary of your testimony?**

A. On every comparative metric that I look at, supply reliability and peak demand services offered by high delivery underground salt dome storage facilities such as those proposed by Magnum are superior to the single service offered by an LNG facility such as the one proposed by DEU.

## **Observations Regarding LNG Supply Reliability or Peaking Facilities verses High Delivery Underground Natural Gas Storage**

**Q. DEU witnesses Mr. Gill and Mr. Paskett discuss permitting and safety issues. (DEU Exhibit 5.0R, page 3, lines 74-77; DEU Exhibit 5.0R, page 5, lines 126-136; DEU Exhibit 5.0R, pages 8 and 9, lines 213-224; DEU Exhibit 4.0 R, page 7, lines 131-133; DEU Exhibit 4.0 R, pages 10 and 11, lines 197-212). What is your experience and understanding regarding the comparative permitting and safety issues of high delivery underground natural gas storage constructed in salt domes verses LNG supply reliability or peaking facilities?**

A. In summary LNG facilities, including peakshavers, require a greater threshold of regulatory oversight in permitting and operations than do underground storage and transmissions pipelines. This additional oversight is primarily driven by the significantly greater potential adversarial impacts of an LNG release due to a partial or complete facility failure resulting in a release of LNG verses that of a pipeline or storage release or failure. By its very nature, LNG contains 600 times more BTUs in a cubic foot of liquid then a cubic foot of natural gas at standard conditions. As such, it has resulted in much greater regulatory oversight for LNG facilities.

Let me illustrate with an overview of the federal permitting process for pipeline/storage facilities and LNG facilities that fall under Federal Energy Regulatory Commission ("FERC") jurisdiction. FERC reports that there are more than 110 LNG facilities operating in the U.S. performing a variety of services. Some facilities export natural gas from the U.S., some provide natural gas supply to the interstate pipeline system or local distribution companies, while others are used to store natural gas for periods of peak demand.

FERC has permitted and maintains oversight of 13 LNG Peakshaving facilities;[1] other agencies also have oversight of these facilities. Further, the FERC is charged with the permitting and oversight of over 300,000 miles of interstate pipelines and over 220 underground storage facilities. FERC is clearly the single most experienced agency with LNG and with pipeline and storage permitting and oversight experience. As such, an examination of the differences in FERC permitting of storage and pipelines compared to LNG plants will illustrate significant differences between these facilities.

During the permitting process of LNG facilities, the FERC requires detailed analyses that are not required for underground storage facilities or pipelines. These additional analyses include a Consequence Analysis that models such things as vapor dispersion, vapor cloud explosion impacts, and fire radiation in the event of an LNG pool fire plus quantitative risk analysis, and process hazard analysis, all of which add layers of complexity to permitting LNG projects over that of pipeline/storage projects.

[1] See www.ferc.gov/industries/gas/indus-act/lng.asp

The additional permitting requirements also are driven by the above ground storage tank(s) that are installed to hold LNG at an LNG facility.  These tanks typically are designed to hold five days or more of peak day send-out, typically up to 4 Bcf (possibly more) of gas in the form of LNG.  Permits for LNG storage tanks sometimes require special design considerations including a double or secondary containment system.   If the tank is breached either due to an unintended failure (i.e. fatigue, construction defect, operational error, etc.) or terrorist attack (tanks are quite large and are readily visible in the landscape making them potentially easy targets) the secondary containment of the exposed LNG would attempt to minimize the potential adverse impacts on life and property.  By its very nature underground storage in salt caverns such as those at the Magnum facility or elsewhere do not have this permitting or safety issue.

The Pipeline and Hazardous Materials Safety Administration ("PHMSA") and FERC require that for land-based LNG facilities, impoundment structures around LNG tanks and pipelines be designed to control the spread of LNG if a release occurs.  Fire and vapor suppression systems must be installed to mitigate the consequences of a release.  Gas detectors, fire detectors, and temperature sensors automatically activate firefighting and vapor suppression systems. In the event of a fire, as a mitigation, water spray may be used for heat affected exposures, or high expansion foam may be used to reduce radiant heat impact on exposures.   At some facilities PHMSA may also require vapor fences to be installed to prevent vapors from extending onto adjacent properties. Vacuum jacketed pipe also be required to provide an additional layer of protection in the event of a release of the inner pipe. Emergency shutdown devices are required to be designed to activate when operational parameters extend beyond the normal operational ranges. The LNG facility operator is required by PHMSA to develop and follow detailed maintenance procedures to ensure the integrity of the LNG facilities various safety systems.

Prior to commencing operations, the LNG facility operator must have established and approved detailed procedures that specify the normal operating parameters for all equipment. When a piece of equipment is modified or replaced, all procedures must be reviewed and modified if necessary to assure the integrity of the system. All personnel must complete training in operations & maintenance, security, and firefighting. The operator must coordinate with local officials and apprise them of the types of fire control equipment available within the facility. Additionally, Federal regulations require tight security for the facility, including controlled access, communications systems, enclosure monitoring, and patrols[2]. Most of these LNG-specific PHMSA and FERC requirements are not applicable to the Magnum underground storage facility or associated natural gas transmission pipeline. As such, the permitting process will likely be a more complex and lengthy process for the LNG facility as compared to the Magnum project.

**Q. How do safety issues of high delivery underground natural gas storage constructed in salt domes compare to LNG supply reliability or peaking facilities?**

A. LNG facilities have a greater burden of operational oversight related to safety than underground facilities or transmission pipelines. LNG facilities have a large number of operational safety requirements that are not applicable to underground storage or

[2] See www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-safety

transmission pipelines. These safety requirements include those imposed by PHMSA, as described above, the FERC, National Fire Protection Association - Standard for the Production, Storage, and Handling of Liquefied Natural Gas ("NFPA 59A"), and state and local safety requirements such as may be required by the Fire Marshall within who's jurisdiction the LNG facility may be built.

The reasoning behind these extraordinary detailed and strict safety requirements stem from the added complexity of handling LNG, a cryogenic fluid, over that of natural gas in its vapor form. LNG at minus 260 degrees Fahrenheit requires all piping, handling, and storage facilities to be constructed of specialty steel (9 Nickle or Stainless steel). By its very nature as a cryogenic fluid LNG has a greater need for safety preparedness. Further, as stated earlier, LNG contains 600 times more BTUs in a cubic foot of liquid then does natural gas at standard conditions. As such, a great deal of operational safety is focused on the event of a spill. Cryogenic tanks and pipes within an LNG facility are required to contain spilt LNG in containment structures. This is intended to prevent an uncontrolled spread of LNG across the ground, accompanied vaporization and potential ignition. LNG facilities are designed to contain a worse-case scenario, that being a complete failure of a full storage tank of LNG. The devastation of a breached LNG tank, even contained within the required containment berm if the vapor cloud is ignited, could be catastrophic to the facility and surrounding environments.

**Q. Are there other similar considerations that you recommend the Public Service Commission of Utah should consider in this case?**

A. Yes. In addition to other issues addressed above, I believe that two critical long-term issues should be carefully evaluated: 1) potential obsolesce of the facility and 2) urban encroachment.

Many LNG facilities have over time become obsolete as the initial underlying justification for the facility no longer exists. Peak day demand is usually the primary justification utilities use to argue for and build LNG Peakers. The common argument made by utility LNG Peaker proponents is that there is insufficient pipeline or proximate storage capacity at economic cost and as such the utility is forced to make the decision to build an LNG facility to meet its current and future customer peak day demand. Over time several factors can cause these initial justifications to fade. These factors include but are not limited to: 1) new pipeline or underground natural gas storage construction or the addition to existing pipeline capacity that occurs independently from the utility building its LNG facility; 2) demand growth overall or in the area where the LNG facility is built does not materialize; 3) technology improvements reduce demand for peak day requirements; and 4) weather pattern changes. If a utility makes the capital investment in an LNG facility that is supported by the utility’s ratepayers today and there is a change in the future that reduces the need for such service, the cost of carrying an obsolete LNG facility may be shouldered by the ratepayers for the remaining life of the LNG facility. In contrast, underground storage used to serve supply reliability and peak day requirements can be contracted for various terms (months to tens of years) and purposes. Thus, if the need for such supply reliability or peak day service diminishes or goes away, the ratepayers only face carrying the storage contract through its termination.

Over time LNG facilities have experienced urban encroachment due to population growth. As a result of such encroachment there is a greater potential for damage to life and property in the event of a catastrophic accident at the LNG facility. Many LNG facilities that were built in the 1970s and 1980s that were once in remote locations relative to urban populations now are surrounded by urban congestion. AGL Resource's Riverdale LNG Facility is a perfect case in point. The images below show the urban area around the Riverdale facility in 1978 and then again in 2018. When this plant was built in the mid-1970s this area was a sparsely populated rural site remote from the Atlanta load center. As urban encroachment occurred, additional life and property have closed in around the facility. Figure 1 Below shows the half and one mile radii around the Riverdale plant in 1978 and Figure 2 shows the same for the facility in 2018. These clearly illustrate the urban encroachment that can occur over time.

Clearly plant obsolesce and urban encroachment and their consequences are things that the Utah Commission should consider in this case.

Figure 1

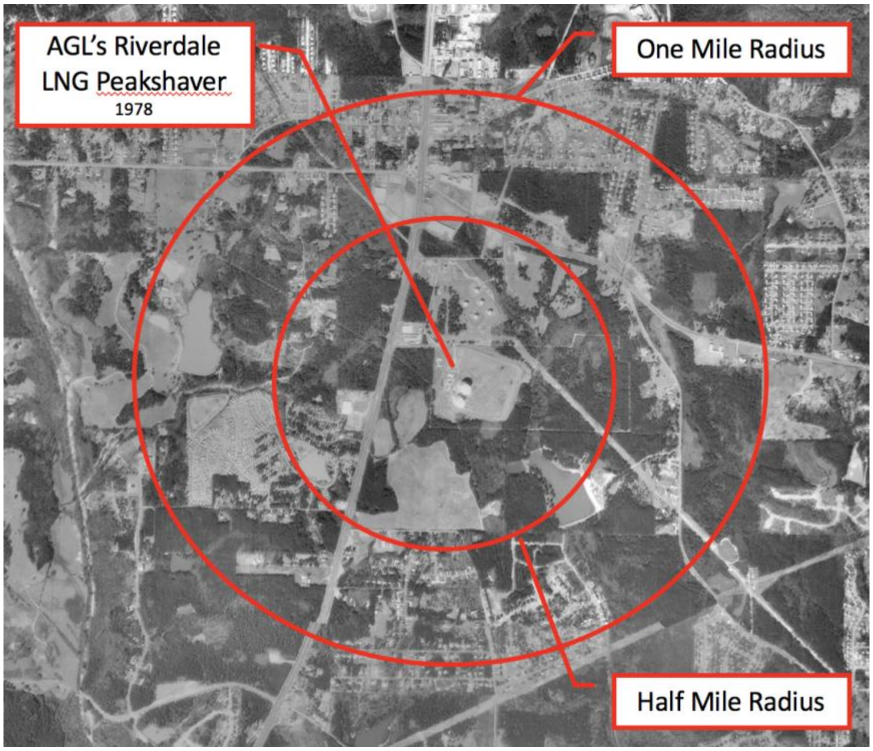
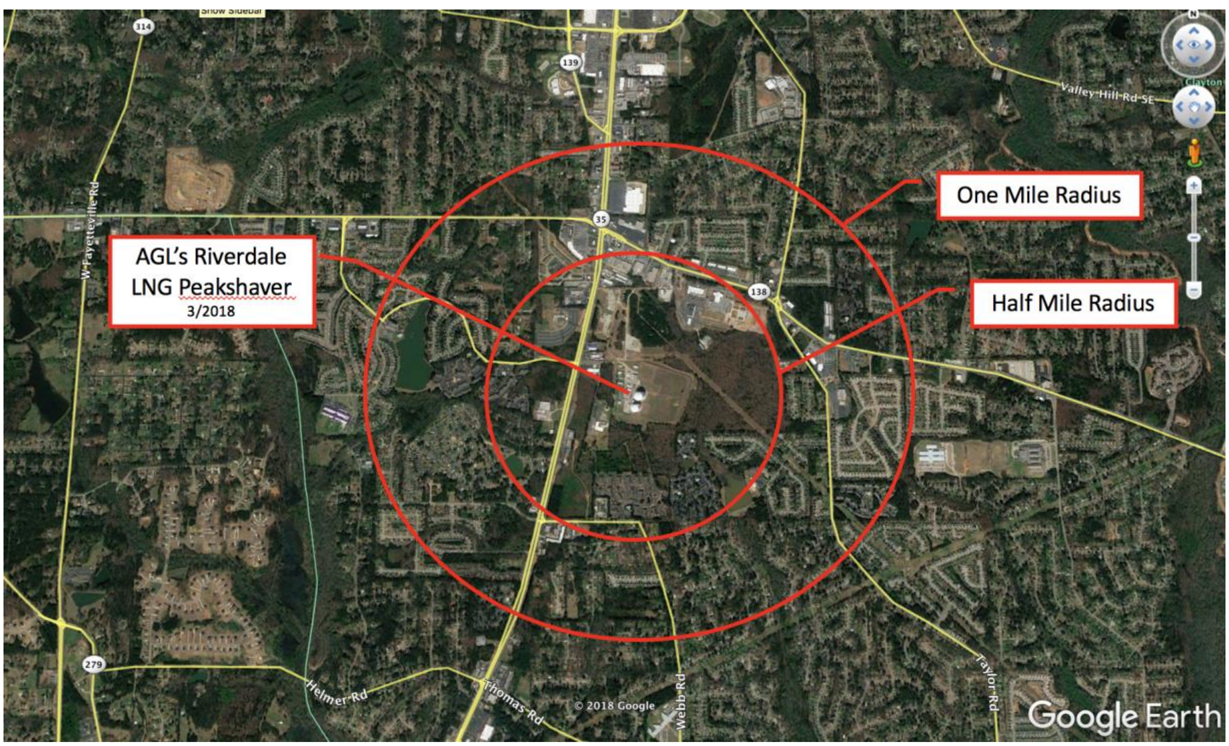

AGL's Riverdale LNG Peakshaver
1978
One Mile Radius
Half Mile Radius

Figure 2


AGL's Riverdale LNG Peakshaver
3/2018
One Mile Radius
Half Mile Radius
Valley Hill Rd SE
W Fayetteville Rd
Helmer Rd
Thomas Rd
Webb Rd
Taylor Rd
314
139
35
138
279
© 2018 Google
Google Earth

**Q. DEU witnesses Mr. Paskett and Mr. Gill discuss operating issues. (DEU Exhibit 4.0R, page 7, lines 131-133; DEU Exhibit 5.0R, pages_9 and 10, lines 247-253). What is your experience and understanding regarding the relative complexity of operating high delivery underground natural gas storage constructed in salt domes verses LNG supply reliability or peaking facilities?**

A. Underground salt dome natural gas storage is significantly less complex than an LNG Supply Reliability/Peaking Facility. High delivery underground salt dome storage is very simple.

Simply put, an underground storage facility receives pipeline supplied gas through a meter and regulator station, compresses it, injects it into the cavern, holds the gas in the cavern, then when required free flows gas out of the cavern back to the pipeline (or as the pressure drops in the cavern, gas may be compressed to deliver gas back to the pipeline). Additionally, ambient air cooling, dehydration and separation equipment may be installed to condition the gas as it moves into and out of storage.

LNG Supply Reliability/Peakers are on the other hand much more complex. Once pipeline gas is received by the LNG facility through a meter and regulator station the gas must be treated to remove impurities to bring the quality of the gas to liquefaction standard. This front-end treatment typically removes water, CO2, H2S, mercury and possibly other impurities. These impurities must be dealt with by the facility operator as a waste product.

Once purified, the gas stream must be chilled to minus 260 degrees Fahrenheit. This process requires a compression cycle, which is similar to the compression used in underground storage in only one way – an engine or motor drives a compressor. After that, the compression at an LNG facility is substantially different than that used in underground gas storage.

Generally, there are two separate compression requirements at an LNG Supply Reliability/Peaking facility: 1) compression used in the refrigeration cycle, and 2) to handle boil off and tail gas. Regarding the refrigeration cycle, the compressor is used to produce a very cold (greater than minus 260 Fahrenheit) working fluid that is used in a heat exchanger (known as a cold box) where the now purified feed gas is converted from a vapor to a cryogenic liquid – LNG. The boil off and tail gas compressor is generally smaller than the refrigeration compressor in terms of horsepower and is typically used to compress boil off gas collected from the LNG storage tank and tail gases produced from the front-end treating to a pressure necessary to either send it out to the utility system or back into the refrigeration process.

Once the LNG comes out of the cold box it must be moved into the LNG storage tank utilizing pumps, pipelines, valves and other associated operating equipment designed and built to handle minus 260 degrees Fahrenheit along with the attendant containment systems in the case of a failure of the cryogenic handling equipment. The LNG storage tank has its own unique operating considerations, including ground heating, security, monitoring, and maintenance. In addition to the tank the LNG itself must be monitored. Over time if the liquid remains in the tank for prolonged periods (i.e. a supply reliability or peak day event has not occurred for several years) the LNG itself will stratify and age in the tank and over time may no long meet pipeline quality specifications as boil off is replaced with new LNG.

With respect to natural gas sendout from the LNG facility to meet peak day requirements, in order for the stored LNG to be utilized by the receiving pipeline or utility system the LNG must be warmed to an acceptable temperature. Vaporizers are used to add heat to the LNG coming out of the tank. There are several types of vaporizers (aside from ambient water or air vaporizers) that require heating the LNG; one very common method is the use of fluid (water/glycol mix of some type) and running the LNG and heated fluid through a heat exchanger to vaporize the LNG. Only once vaporized can natural gas be formed to be sent out to the utility/pipeline.

In summary, once built, the facilities necessary to produce, store, and send out vaporized LNG from an LNG Peaking facility to meet a utilities supply reliability requirement or a Peak Day Demand are significantly more complex than those required at an underground salt dome storage facility to meet the same requirements.

**Q. DEU witnesses Mr. Gill and Mr. Mendenhall address capital and operating costs of the various options. (DEU Exhibit 5.0R, page 8, lines 202-210; DEU Exhibit 1.0R, page 9, lines 211-221), What is your experience and understanding regarding the relative short- and long-term operating costs of high delivery underground natural gas storage constructed in salt domes verses LNG facilities?**

A. Underground natural gas storage constructed in salt domes due to their simplicity compared to LNG supply reliability/peaking facilities are significantly lower in cost to operate in both the short- and long-term.

As described above underground natural gas storage constructed in salt domes have a much simpler regime of operating equipment than an LNG facility. As, such the annual Operation and Maintenance ("O&M") expense is lower from underground natural gas storage than from an LNG facility. Additionally, the human resources required to operate and maintain a more complex system are greater than simpler systems – meaning fewer full-time equivalent hours are required to operate underground natural gas storage than an LNG Facility. The budget for short-term O&M is higher for an LNG Supply Reliability/Peaker than underground natural gas storage. Further the risk of these O&M costs for a utility-owned LNG Supply Reliability/Peaker may be borne by the ratepayers, while the risk of O&M expenses from contracted underground natural gas storage are typically borne by the owner of the contracting gas storage facility.

In the long-term, the necessary over-haul costs of equipment for a more complex system such as an LNG Supply Reliability/Peaker compared to underground natural gas salt dome storage are greater due to the amount of equipment and cryogenic nature of the LNG Supply Reliability/Peaker verses the underground natural gas storage facility. Given that the compressor's prime movers are electrically powered there should be a concern regarding at least two issues 1) the rate increases that occur by the serving electric utility over time, and 2) the system reliability of the electric utility. History has shown that electric costs have generally increased more rapidly than natural gas costs, giving gas fueled compression an advantage over electric drives. Service reliability is critical; for many of the same reasons that a gas company faces peak demands, electric companies do as well – i.e. extreme cold weather. In this situation, if the electric grid feeding the LNG facility should fail in some manner the performance of the LNG facility could be significantly and adversely impacted.

**Q. Is it appropriate to compare the underlying capital and operating costs of Magnum's facility to the underlying capital and operating costs of the DEU's LNG facility?**

A. No. In short, the capital and operating costs associated with the LNG facility proposed by DEU are costs that would likely directly flow through to rates to DEU's customers. There will be arguments between various classes of customers on the DEU system as to which class should shoulder the brunt of these costs. Industrial customers will argue that they get little benefit for the LNG facility as they would likely be curtailed during a peak day event. Residential customers will likely say that these costs are too great and will result in an unacceptable increase in rates. Whether or not these arguments emerge right away, as the O&M costs of the LNG facility go up as it ages they will likely manifest themselves.

The capital and operating costs of Magnum's facility will likely be a negotiated value in the arms-length contract between DEU and Magnum and as such all risks of O&M on the Magnum facility will be borne by Magnum.

**Q. DEU witnesses Mr. Paskett and Ms. Faust attempt to address flexibility and reliability of the options. (DEU Exhibit 4.0R, pages 1 and 2, lines 18-35; DEU**

**Exhibit 2.0R, page 12, lines 296-300). Can you describe the differences in operating flexibility and reliability of high delivery underground natural gas storage constructed in salt domes as opposed to LNG facilities to meet an LDC's supply reliability or peak demand?**

A. LNG Supply Reliability/Peakers have a typical pattern for use. However, if the LNG Storage tank was emptied during the last heating season and liquefaction commenced in the spring as natural gas demand falls and prices typically decline as well, the liquefier is started and LNG is produced daily such that by the time the next winter starts the LNG tank is full. Typical LNG Supply Reliability/Peaker design allows for roughly 200 days to fill the tank and 3 to 7 days to empty the tank during a utility's Supply Reliability or Peak Demand events. For example, an LNG Supply Reliability/Peaker may be designed to liquefy 10 MMcf/d and in 200 days have 2 BCF of LNG in its tank. Given the facility was designed to send out 400 MMcf/d (an amount that the utility determined would meet its peak day demand) the tank would be emptied in 5 days of operation. In effect, the LNG Supply Reliability/Peaker provides one-turn service over the course of a year. This one-turn design causes the utility to view its LNG resource as the last resort to meet its supply reliability or peak day demands. Some years there may be no need to call on the plant and other years it may be fully depleted during the heating season.

High deliverability natural gas salt dome storage, in contrast, is designed to have the capability to turn from 6 to 12 times per year depending of the specific facility design. For example, if a storage cavern was designed to perform 6 turns per year and had a working gas capacity of 12 BCF, that means that with balanced injection and withdrawal the facility could inject 400 MMcf/d for 30 days and fill the cavern and then withdraw 400 Mcf/d for the next 30 days, and then repeat it 6 times again over the course of the year. There are effectively infinite variations of injection and withdrawal rates that can be tailored to meet a contracting utility's storage requirements for Supply Reliability and Peak Day service.

Additionally, multi-turn service not only provides greater deliverability then LNG, it also provides greater assurance of supply reliability. This reliability can manifest itself in larger volumes of storage than the LNG tank that could be utilized even during summer months during a supply disruption. The LNG Facility cannot risk sending out product in the summer because it would eliminate liquefaction days and risk being left short of a full tank going into the winter.

Regarding reliability, the simplicity of design and operations of a salt dome storage cavern insures a higher level of reliability than an LNG facility where there are so many more single points of failure. To achieve the same level of reliability an LNG Facility would have to add significant capital cost to be sure that its liquefaction and sendout capability would equal that of natural gas salt dome storage.

In short, when a utility contracts for multiple-turn service injection, withdrawal, and storage from a provider of high deliverability natural gas salt dome storage, it allows that utility to capture significant operational and economic advantages over a one-turn LNG Supply Reliability/Peaker.

**Q. Are there any other observations that can be made that support high delivery underground natural gas storage constructed in salt domes as opposed to LNG facilities to meet supply reliability and/or peak demand?**

A. Yes. First, I believe that most natural gas companies when faced with a need for storage service have selected underground natural gas storage as the preferred alternative over LNG Supply Reliability/Peakers. Otherwise, there would be 4 TCF of LNG supply reliability/peaking capacity in the U.S. instead of 27.8 BCF. Today in the U.S. there is roughly 4 TCF of underground natural gas storage capacity and only about 27.8 BCF of LNG storage. Specifically, LDCs have sought underground natural gas storage as their preferred alternative when the storage is near and can be quickly delivered into their load centers.

To illustrate this point, the Arizona Corporation Commission ("ACC") in 2014 granted pre-approval of a Southwest Gas Corporation ("Southwest Gas") application to construct an LNG facility. This decision was made in part as a result of there being no proximate underground storage in Arizona or Nevada. A concern over lack of underground natural gas storage was shared by the previous ACC Chairman Doug Little; in 2016 he stated that Arizona's lack of underground gas storage "is a huge gaping hole" in the state's energy infrastructure and that investors he spoke to about power or gas projects are "concerned that we have no storage." [3] I believe that if there had been underground natural gas storage available to Southwest Gas similar to how the Magnum

[3] https://www.argusmedia.com/en/news/1335202-kinder-morgan-proposes-arizona-gas-storage-project

storage is available to DEU, Southwest Gas and the ACC would have opted for underground storage over the LNG facility.

Second, natural gas storage facilities can be generally characterized as providing services in production or market areas. Magnum can provide market area service via its storage facilities and pipeline header system due to the close proximity of the storage cavern to the greater service area of DEU, and direct interconnect of the Magnum pipeline header system to DEU at potentially multiple locations. Market area storage service allows the utility buyer of these services to have immediate access to flowing supply and, in the case of Magnum's proposal to DEU, on a no notice basis – open the valve and gas flows. In contrast to market area storage, the proposed LNG facility of DEU would need notice to prepare to vaporize the LNG. Depending on the type of vaporization used, hours, if not days, will be required to preheat the vaporizers to insure gas will flow into the DEU system.

In summary, I believe highly reliable, flexible, lower cost peak day services like those offered by the Magnum facilities are superior for supply reliability and/or peaking services than an LNG plant. Moreover, other short- and long-term cost and operational benefits of the Magnum storage project will provide ratepayers of DEU with less cost and far greater protection against obsolescence.

**Q. Does this conclude your testimony?**

A. Yes.

Magnum Exhibit 2.1SR

**David J. Schultz**
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**Sugar Land, Texas 77479**
**daveschultz20@gmail.com, (832) 418-0811**

***SUMMARY***

**Energy Executive** with the broad range of experience, skills and success necessary to grow and sustain value for the visionary energy firm. Emphasis on multi-disciplined approach in finding original solutions to complex issues facing energy companies and their clients.

***PROFESSIONAL EXPERIENCE***

**Owner/Partner**
**New World Global, LLC and New World Fuel SA de CV** *1/1/16 to Present*

Founder and Partner with two Mexican nationals of complementary companies in the U.S. and Mexico with the primary purpose to capture energy related market share and assets that become available due to the Mexican Energy Reform and the retreat of Pemex and CFE from their respective monopoly positions because of the Reform.

Since inception we have built the company into one of the largest independent suppliers of LNG and Propane to Mexico and in February 2017 will begin to supply refined products as well.

- Developed detailed logistics procedures for the cross-border movement of hydrocarbon products
- Established and executed commercial agreements for the international procurement of fuels
- Set up internal financial and operational procedures
- Largest exporter by land of LNG
- One of the top exporters of Propane
- First year sales approaching $10 million without any debt
- Projected second year sales projected $30 million

**Independent Consultant** *1/05 to Present*

Provides insight and analysis regarding development, commercial and operational aspects of energy concepts/projects involving natural gas, natural gas storage, LNG, and power generation.

Engaged by proponent of small scale LNG facilities to serve merchant and utility demands for various projects in the U.S. and Mexico.

Engaged by an India/Singapore group developing a small-scale LNG import terminal (up to 1.25 MTPA) in Southern India. Scope of work is to advise the group regarding among other things the:

- Technical and commercial aspects of the terminal including permitting, EPC, and operations
- Issues associated with the marine acquisition and receipt of LNG from international points of supply as well as the distribution supply chain – pipeline, tanker, and bunkering – in country
- Evaluated the competitive issues of imported LNG verses in country storage

Acted as lead negotiator and directed bid on behalf of a private firm for a Caribbean Island Electric Utility

- Negotiated terms of sale for the purchase of a $60 million electric generation and distribution utility
- Prepared and won the bid for the purchase
- Hired and lead contractors for and through the due diligence review

**LNG America LLC**
*Senior Vice President* *9/13 to 12/15*
Since company start-up lead the strategic development for commercial and asset deployment. Number two person in the company. LNG America's focus is on the domestic and marine use of LNG as a substitute to traditional petroleum based fuels.

- Successfully negotiated supply agreements with various LNG suppliers including from the largest LNG supplier in North America for LNG - up to 500,000 per day
- Implemented strategic cooperative marketing agreements with various participants throughout the LNG supply chain including with end-users
- Positioned LNG America as a leader in the marine segment of the LNG fuel marketplace
- Negotiated contracts for the provision, marine architect, class society, and cryogenic equipment supplier for the first of its kind LNG marine bunker barge
- Key member of management team soliciting venture funding for LNG America

**Pivotal LNG a Subsidiary of AGL Resources**
*Vice President and General Manager – Pivotal LNG* *10/10 to 9/13*
Leader of all aspects of AGL Resources move into the merchant LNG marketplace to establish LNG as an economic and environmentally friendly substitute to diesel.

- Established Pivotal LNG as an operating subsidiary of AGL Resources
- Developed merchant LNG sales contract and negotiated sales of over 250 million gallons of LNG
- Negotiated the purchase and conversion to merchant status of a 22 million LNG gallon per year municipal LNG production facility
- Leading merchant LNG facility development strategy
- Directing AGL Resources participation in the ANGA/AGA/CATA NGV study

**Pivotal Energy Development a Unit of AGL Resources**
*Vice President – Asset Development* *6/08 to 10/10*
*Managing Director* *6/05 to 6/08*
Leader of gas project development activities within Pivotal Energy Development a unit of Atlanta based AGL Resources.

- Lead project team for a $330 million natural gas storage project – placed in service September 2010
- Complete responsibility for a $1.1 billion LNG import terminal and pipeline in the mid-Atlantic region of the U.S., including FERC permitting, engineering, design and construction, NIMBY, and political affairs

**Energy Transfer Group**
*Partner Duel Drive* *5/01 to 5/05*
Responsible for the development and implementation of various start-up business lines including

- A proprietary natural gas compression technology that utilizes either natural gas or electricity as fuel to power reciprocating gas compressors creating an energy arbitrage opportunity - Total deployed capital nearly $60 million
- Development, acquisition or sale of nearly 300 Mw of peaking power plants in California, New Mexico, Texas and Florida

**Reliant Energy**
*Director – Project Development* *2/00 to 5/01*
Responsible for all phases of the development of merchant generation and industrial cogeneration facilities including siting, environmental review and permitting, design, engineering, and financing

*Director – Industrial Electricity Sales and Fuels Procurement* *4/99 to 2/00*
One of Reliant's expatriates in the Netherlands to monetize its investment in UNA, one of the Netherlands largest power generation companies.

*Director - Industrial Development* *11/98 to 4/99*
Responsible for identifying, structuring and closing long term electric and gas transactions with utility and industrial customers.

**Duke Energy Corporation (and predecessor companies)**
**Duke Energy Power Services, Inc.**
*Managing Director, Operations* *11/97 to 11/98*
Manage the integration and on going financial and physical performance of existing, acquired and newly constructed power generation facilities owned by Duke Energy Power Services (DEPS).

*Managing Director, Development and Structuring - Southeast* 6*/97 to 11/97*

Lead the identification, development, and structuring of power generation opportunities in the Southeast U.S.

*Director, Operations Development* 9/*96 to 6/97*
Responsible for the development of the operational structure, procedures and administrative policies of the predecessor companies to DEPS.

**Pacific Gas Transmission Company**
*Project Manager, 1995 Construction Program* 1/*93 to 9/96*
Led all aspects of Pacific Gas Transmission Company's 1995 Construction Program.

*Manager of Public Information, Pipeline Expansion Project* *6/92 to 1/93*
Responsible for media and public information dissemination regarding the construction activities associated with construction of the $1.7 billion Pacific Gas Transmission Company-Pacific and Electric Company Pipeline Expansion Project from Canada to central California.

*Director, Regulatory Affairs and Policy Planning* *1/89 to 6/92*
Managed all phases of Pacific Gas Transmission Company's regulatory filings with the Federal Energy Regulatory Commission and the California Public Utilities Commission regarding the Pacific Gas Transmission Company-Pacific and Electric Company $1.7 billion Pipeline Expansion Project.

**San Diego Gas and Electric Company**
*Regulatory Affairs Project Manager* *9/88 to 1/89*
Prepared and submitted company applications, testimony, exhibits and related filings in CPUC proceedings.

*Senior Pricing Analyst* *11/87 to 9/88*
*Pricing Design Analyst* *7/86 to 11/87*
*Rate Analyst* *7/85 to 7/86*
*Conservation Planning Analyst* *6/84 to 7/85*
*Conservation Specialist* *1/82 to 9/84*

**Industry Speaking**
Spoken at nearly 50 LNG, Storage, Power Generation, and LPG industry events regarding projects or various aspects of how such operations affect their overall performance and economic viability.

***EDUCATION & TRAINING***
**SAN DIEGO STATE UNIVERSITY**
*B.A. Political Science* *12/77*
*M.A. in Political Science (course work)* *5/82*

**Certificate of Service**

**Docket No. 18-057-03**

A true and correct copy of the foregoing was served by email this day 20th day of September 2018 on the following:

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/s/ *Sara Turner*