Application: A.20-11-XXX

Witness: K.Woo, D.McQuilling, K. Lang

Chapter: 4

PREPARED DIRECT TESTIMONY OF

KEVIN WOO, DAVID MCQUILLING, AND KEVIN LANG

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, PACIFIC GAS AND ELECTRIC COMPANY, AND SOUTHWEST GAS CORPORATION

(TECHNICAL)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

November 2020

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CHAPTER 4

PREPARED DIRECT TESTIMONY OF

KEVIN WOO, DAVID MCQUILLING, AND KEVIN LANG

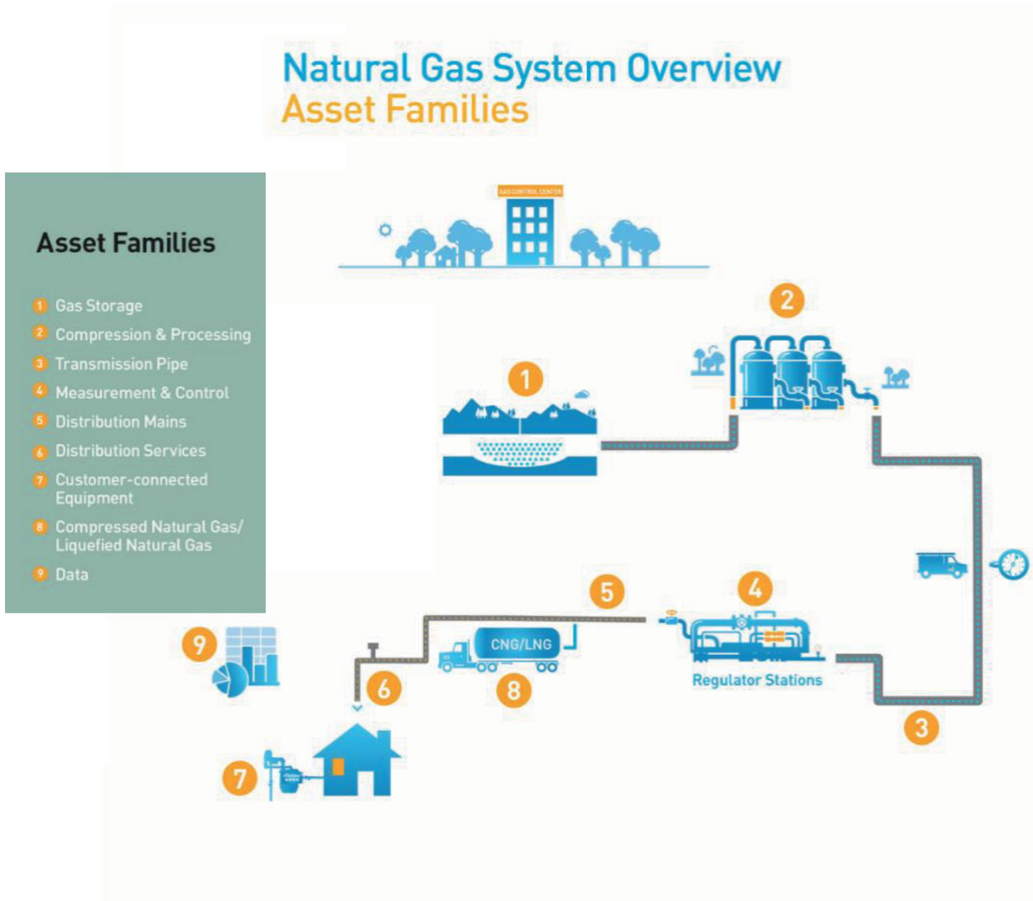
(Technical)

I. PURPOSE

The purpose of this jointly prepared direct testimony on behalf of Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the Joint Utilities) is to provide status and detail on literature reviews, research, and studies conducted by the Joint Utilities to determine the feasibility of utilizing the existing natural gas infrastructure in California, or portions thereof, for hydrogen blending. This assessment has considered hydrogen blending compatibility with the various natural gas asset families (see Figure 1 below), which encompass natural gas infrastructure materials, compressors, turbines and engines, end user equipment, and underground storage, and how blended hydrogen will affect natural gas operations such as metering, emissions, leak detection, and overall gas system reliability.

Figure 1

Asset Families of Natural Gas System



This testimony will outline work completed to date, explain any conclusions or proposed mitigations, and identify what additional work is planned to allow the Joint Utilities to propose a program for injecting hydrogen. This testimony is focused on technical areas and is related to the system operations discussed in Chapter 1: Safety, System Integrity, and Reliability, to demonstrate why a preliminary hydrogen injection standard is not being proposed at this time. This chapter also provides details on why hydrogen blending demonstrations (see Chapter 3) and additional research are needed to inform a future standard. Where possible, mitigation options are provided for possible paths forward (but such paths are not necessarily comprehensive or reflect all potential options known at this time).

Research indicates that hydrogen-natural gas blends may be compatible now or in the near term (approximately within 5 years) with portions of existing polyethylene (PE) natural gas distribution systems, depending on the types of appurtenances, end user equipment, and varying system conditions. Successful completion of the demonstration projects outlined in Chapter 3 may accelerate the estimated 5-year time for hydrogen injection into controlled and isolated portions of the existing natural gas system. Additional research is warranted to comprehensively evaluate system configurations, components, construction methodologies, and materials of construction to encompass the variety and categories of piping systems for each utility.

Several research projects and initiatives are underway around the world which can help to further study the impact of hydrogen-natural gas blends in U.S. Department of Transportation (DOT)-defined transmission systems. Multiple international research initiatives are underway to further evaluate and mitigate risks associated with material compatibility, compression, processing, storage, measurement, regulation, and use of hydrogen-natural gas blends at higher pressures where it has been observed that risks may increase. Therefore, the Joint Utilities recommend prioritizing blending in PE distribution systems and conducting further research on new and existing steel systems in California's natural gas infrastructure before proposing a hydrogen injection standard.

II. HYDROGEN BLENDING SAFETY

The foundation of establishing a hydrogen injection standard will be to confirm safety in each aspect of operation and maintenance of the natural gas system, including pipeline safety, system integrity and reliability of service. Since hydrogen and natural gas have different properties, a preliminary focus is outlined on leakage rates, leak detection, odorants, and electrical equipment compatibility that may be impacted after hydrogen is injected into the natural gas supply. Observations, recommendations and mitigative measures on other technical topics follow in the other sections. The following subsections detail the current knowledge on these topics.

A. Leakage Rates

The research and studies referenced in this section suggest that the presence of hydrogen does not significantly increase leakage rates for natural gas steel distribution systems (i.e., piping, fittings, appurtenances) included within the scope of each study outlined in Chapter 3. In 2017, the SoCalGas Engineering Analysis Center (EAC) evaluated gas leakage through steel pipe fittings (utilized by SoCalGas) using hydrogen-natural gas blends with 5 to 8% hydrogen. Leaks were simulated and controlled by adjusting needle valves and brass fittings installed on the test systems. In a 61 to 66 pounds per square inch gauge (psig) test scenario, there was no significant difference in pressure drop rate between the hydrogen blend system and the natural gas system. In a 10- to 12-inch water column test scenario, the hydrogen blend system had an approximately 6.4% higher pressure drop rate (i.e. approximately 4.8 x 10^{-4} inches water column per minute difference) than the natural gas system. The minimal to insignificant difference in pressure drop rate between the natural gas and hydrogen systems indicates that hydrogen does not cause a significant change in leakage rate of a hydrogen-natural gas blend for a low-pressure steel distribution system.

A University of California, Irvine (UCI) study yielded similar results.[1] UCI tested leakage rates using an existing natural gas steel piping system inside a building with a 10% hydrogen-natural gas blend operating at 46 inches water column. The average pressure drop rates for natural gas and the hydrogen-natural gas blends were the same within experimental error. The 10% hydrogen blend appeared to have a slightly higher pressure drop rate, but the leakage difference was within the pressure transducer's accuracy (0.25% full scale of 0 to 2 psig). Therefore, the higher leakage difference was not statistically significant.

Conclusions from a National Renewable Energy Laboratory (NREL) study suggest that hydrogen's leakage rate is about three times that of natural gas,[2] but the UCI and SoCalGas studies demonstrated that leakage rates did not significantly increase for the hydrogen-natural gas blends tested. Since there is a variety of test results, additional research is warranted to further investigate leakage rates by using utility-specific parameters and various leak sizes and hydrogen content to obtain more conclusive results.

B. Leak Detection Equipment

The leak detection and measurement equipment currently used by the Joint Utilities is designed for methane.[3] In order to detect both hydrogen and methane at low blend percentages,

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[1] Alejandra Hormaza Mejia et al., Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure, 45 Int'l J. of Hydrogen Energy 8810, 8826 (2020).

[2] M.W. Melaina et al., National Renewable Energy Laboratory, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues (March 2013), *available at* https://www.nrel.gov/docs/fy13osti/51995.pdf.

[3] Typical commercial natural gas contains 85 to 90 percent methane. *See* Brittanica, Composition and Properties of Natural Gas, *available at* https://www.britannica.com/science/natural-gas/Composition-and-properties-of-natural-gas.

leak detection devices using semiconductors are generally considered suitable.[4] However, suitability with each technology is not yet known. A consortium of French gas operators performed a technical review of leak detection equipment and determined that additional research is required to determine the effectiveness of various leak detection device types for hydrogen-natural gas mixtures.[5] Leak detection devices that are unable to detect hydrogen need to be identified; such equipment will need to be recalibrated or replaced to identify a lower level of methane. In addition, gas detection systems are static and would not be able to dynamically change to suit the hydrogen-natural gas blend if it changes or has a larger variability than 10%.[6] Hydrogen in gas detection devices can lead to improper operation or non-detection of a hazardous atmosphere.[7] Therefore, it is essential to determine if hydrogen will impact the accuracy, performance, and lifespan of the equipment deployed by the Joint Utilities and if new types of leak detection and measurement equipment or technologies are required once hydrogen is introduced to the pipeline system.

The United Kingdom's HyDeploy project tested several gas detectors with hydrogen blends. Test results suggest that hydrogen exposure causes catalytic reaction detectors to yield higher %Lower Explosive Limit (LEL) readings, infrared (IR) detectors to yield lower %LEL readings and vol% readings, and thermal conductivity (TC) detectors to yield higher vol% readings.[8] Previous studies also suggest that hydrogen variability will impact gas detection systems since instrumentation is usually calibrated with a known gas.[9]

SoCalGas is in the process of evaluating currently deployed equipment types using various hydrogen-methane blends up to 20% hydrogen. The types of technologies that will be evaluated include IR, TC, flame ionization detector (FID), and catalytic reaction. This project is

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[4] Daniel Krosch & Briony O'Shea, COAG Energy Council, Hydrogen in the Gas Distribution Networks: A kickstart project as an input into the development of a National Hydrogen Strategy for Australia (Jan. 11, 2019), *available at* http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-hydrogen-in-the-gas-distribution-networks-report-2019_0.pdf.

[5] GRTGaz, Technical and economic conditions for injecting hydrogen into natural gas networks (June 2019), *available at* https://www.grtgaz.com/fileadmin/plaquettes/en/2019/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf.

[6] Krosch, *supra*.

[7] P. E. Dodds & S. Demoullin, 38 Int'l J. of Hydrogen Energy 18, 7189, 7200 (2013).

[8] J.E. Hall et al., Gas Detection of Hydrogen/Natural Gas Blends in the Gas Industry (2019), *available at* https://hysafe.info/iahysafe/wp-content/uploads/2019_papers/128.pdf.

[9] Krosch, *supra*.

estimated to be completed by the end of 2020, and it will help inform the Joint Utilities if new types of leak detection equipment and/or technologies are needed for hydrogen blending in the pipeline system.

C. Compatibility with Existing Odorants

The Joint Utilities surveyed primary odorant vendors to evaluate whether the current odorant used (tert-butyl mercaptan (TBM) and tetrahydrothiophene (THT)) will continue to be effective when hydrogen is injected to the natural gas supply. The vendors noted that hydrogen will not affect the stability of these odorants and the same odorants are suitable when hydrogen is present. The Joint Utilities will need further investigation or research to fully evaluate all utility-specific odorants.

D. Compatibility with Electrical Equipment

The National Fire Protection Association (NFPA) 70, National Electrical Code uses a gas's minimum ignition current (MIC) ratio and maximum experimental safe gap (MESG) to determine the gas's hazardous group, upon which facility designs are based. Since hydrogen and methane[10] fall under different hazardous groups, there is concern that a hydrogen-natural gas blend could trigger a group reclassification and will require upgrade or replacement of electrical systems at existing facilities. However, past research suggests that methane blends with up to 14% hydrogen would not lead to a hazardous group reclassification.[11] The Joint Utilities will need further investigation or research to fully evaluate the safety of existing electrical systems installed in proximity to hydrogen-natural gas piping systems.

III. SYSTEM INTEGRITY

A. Material Compatibility

Natural gas infrastructure is a complex network of piping, valves, fittings, equipment, and appurtenances that are typically comprised of plastics, elastomers, and/or metals (e.g., carbon steel, stainless steel, iron, aluminum, brass, copper). The largest single component is the piping system, which is generally continuous plastic or continuous steel joined through fusing or welding. A variety of mechanical fittings, to include compression, flanged, and threaded fittings are also utilized on gas piping systems. The vast majority of gas piping systems are buried, and a

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[10] Typical commercial natural gas contains 85 to 90 percent methane. *See* Brittanica, *supra*.

[11] A. Janès et al., Experimental determination of minimum ignition current (mic) for hydrogen/methane mixtures for the determination of the explosion group corresponding to iec 60079-20-1 standard (2017), *available at* https://pdfs.semanticscholar.org/1de1/5de87dcda973ae4beb1b1f2880993d54770a.pdf.

mixed system of PE and steel is not uncommon. Aboveground piping is primarily constructed of steel and utilizes a variety of connection methods. The following sections discuss compatibility of these materials with blended hydrogen based on literature reviews, research and studies to date and additional planned research.

In general, PE gas piping is compatible with blended hydrogen, whereas the properties of steel (piping, welds, valves, fittings, equipment) can degrade. The degradation process, known as hydrogen embrittlement, is most pronounced in higher strength steels and some existing steel welds (e.g., pre-1970).

A wide variety of elastomers are utilized as seals in valves, fittings, equipment, and appurtenances in natural gas systems and some elastomers may not be compatible with hydrogen service. Additional research is needed to evaluate the suitability of all elastomers (types and classifications) utilized in each utility and customer system (see PE Pipes – Elastomers, *infra*).

In general, the Joint Utilities, through further research and studies, will need to categorize material and equipment compatibility with hydrogen blending in order to identify potential replacements and/or retrofit of sections of existing natural gas infrastructure.

1. PE Pipes

PE pipe is the primary material used in new distribution systems. Research to date indicates that hydrogen does not degrade PE pipes.[12,13,14] Research has also shown that hydrogen loss due to permeation through PE pipes would be relatively small and insignificant in terms of safety.[15] Several international hydrogen blending pilots (referenced in Chapter 3) utilized PE pipeline systems and showed similar results where hydrogen had minimal effect on PE pipes.

Note that PE pipeline systems also include a variety of fittings and components constructed of various polymers, metals, and elastomeric seals. Most studies did not detail the impact of hydrogen on the polymer components beyond pipe, and further investigation is needed to assess the compatibility of these components with hydrogen.

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[12] Krosch, *supra*.

[13] Henrik Iskov & Stephan Kneck, Using the Natural Gas Network for Transporting Hydrogen – Ten Years of Experience, International Gas Union Research Conference (2017), *available at* https://www.dgc.dk/sites/default/files/filer/publikationer/C1703_IGRC2017_iskov.pdf.

[14] Melaina, *supra*.

[15] JP Hodges et al., Health and Safety Laboratory, Injecting hydrogen into the gas network – a literature search (2015), *available at* https://www.hse.gov.uk/research/rrpdf/rr1047.pdf.

a) Elastomers

Elastomers and rubbers are used to provide gas-tight seals in many pipeline components. Previous studies have shown that elastomers and rubbers can swell and/or develop voids after exposure to pure hydrogen.[16] Therefore, the Joint Utilities are supporting additional research efforts to determine if hydrogen blends will have similar effects. The Joint Utilities are partnering with NYSEARCH to study the impact of hydrogen-natural gas blends on elastomers (up to 20% hydrogen). It is anticipated that this research will be a multi-phase effort. Phase 1 of this effort (10-month duration) includes: (a) establishing the range of hydrogen-natural gas composition of interest, (b) identifying the components of the distribution network that could potentially be affected by the varying gas composition, and (c) carrying out a preliminary test program in the laboratory under realistic conditions to establish the level of response of these materials in the presence of hydrogen. It is anticipated that additional future phases will be used to carry out a complete and systematic test program covering all hydrogen blends, materials (new and existing), and operating conditions (pressure and temperature) of interest. In addition, a potential mitigative measure is to develop plastic system components and replacement parts that are designed to be compatible with hydrogen.

b) Meter Set Equipment

Meter set assemblies can contain components and connections with materials that will need further evaluation for hydrogen compatibility, especially elastomers, rubber boots, and seals. SoCalGas and PG&E surveyed their meter manufacturers on hydrogen compatibility. The survey produced mixed responses, with some manufacturers reporting up to 5% hydrogen being acceptable while others allowed up to 100% hydrogen. Some manufacturers noted that more research is needed to determine a limit. The Joint Utilities will confirm accuracy and integrity compliance through internal evaluation. Gas density is a critical component required to accurately calibrate ultrasonic and orifice meters that are widely used for large volume applications. Anticipated fluctuations in hydrogen-natural gas concentrations will affect gas density and in turn impact meter accuracy. All meter components (metallic assemblies, internal components, elastomers, etc.) must be evaluated to determine potential impacts of hydrogen

[16] Nalini Chulliyil Menon et al., Sandia National Laboratory, Polymer Behaviour in High Pressure Hydrogen Helium and Argon Environments as Applicable to the Hydrogen Infrastructure (2017), *available at* https://www.osti.gov/servlets/purl/1464594.

service and whether the meters can provide required measurement accuracy for hydrogen-natural gas service. Since hydrogen energy density is one-third that of natural gas, additional gas flow may be required to deliver equivalent energy content to customers. As such, meter set assemblies, regulator stations, and customer contracts may need to be evaluated and possibly enhanced, supplemented, and/or replaced.

Meter components in distribution systems are typically connected with national pipe thread (NPT) tapered threads, which rely on a wide variety of thread sealants for gas-tightness. Further investigation is needed to assess the compatibility of threaded connections with hydrogen-natural gas blends. Threaded connections are common components within a natural gas distribution system and the assessment of leakage through threaded fittings must be evaluated and addressed. As system pressures increase, flange connections in meter set designs become more prevalent. Flange gaskets, typically made of compressed fibers with a binder, must be evaluated for compatibility with hydrogen-natural gas blends as there are no known current studies.[17]

Similarly, regulators typically include elastomeric sensing diaphragms and seals, and additional investigation will be needed to assess the compatibility of pressure regulators with hydrogen. The lower energy content of a hydrogen blend can also increase a customer's flow demand, which can have capacity implications for service regulators.

2. Steel Pipelines

Hydrogen dissociates on many metal surfaces, dissolves into the metal lattices, and changes the mechanical response of the metal. This phenomenon is referred to as hydrogen embrittlement, and research shows it has a greater impact on high tensile strength steels and steel welds than low tensile strength steels. Hydrogen embrittlement is one of the most relevant study areas that must be fully explored in order to maintain system integrity on steel pipe, fittings, welds and welding operations. The rate and severity of hydrogen embrittlement is influenced by pressure, temperature, hydrogen concentration, stress level, metal composition, metal tensile strength, grain size, microstructure, type of impurity in the metal structure, and heat treatment

[17] See Elastomers, *supra,* for information on gas seals.

history. Hydrogen embrittlement is not found in certain stainless steels, copper, or various irons including ductile, grey cast iron, and wrought iron.[18]

Hydrogen embrittlement lowers the ductility of carbon steels and can reduce the load carrying capacity of gas piping systems. Hydrogen embrittlement lowers fracture toughness and can accelerate fatigue crack growth on pipelines that experience pressure cycling and varying load demand. The lower fracture toughness means that the flaw tolerance of the pipe is reduced, which will necessitate more repairs when flaws are detected. Additionally, the introduction of hydrogen will require closer assessment and effort for continued alignment and compliance with Title 49 Code of Federal Regulations § 192.712 (Analysis of Predicted Failure Pressure), a Pipeline and Hazardous Materials Safety Administration (PHMSA) regulation that requires determination of fracture toughness.

It is critical to understand how existing steel piping, components, and equipment in the California natural gas systems will respond to hydrogen, given the variation in age and composition. This understanding will allow the Joint Utilities to make informed decisions on mitigations such as implementing hydrogen blending in select portions of the network, prohibiting hydrogen blending in other portions, and potentially replacing incompatible components. These mitigative measures will make the natural gas infrastructure less susceptible to embrittlement. Replacements and retrofits and/or increased inspection on steel transmission pipelines will be significant considerations.

The Joint Utilities' analysis of literature reviews, computer simulations, and laboratory testing evaluated hydrogen embrittlement in various hydrogen environments with only one known project, NATURALHY, that included hydrogen-methane environments (0% to 100% hydrogen) with new and existing natural gas steel pipe. Given the limited data on hydrogen embrittlement in hydrogen-methane environments, SoCalGas has initiated a study with DNV GL to test pipeline steel samples exposed to various hydrogen-methane blends and compare with pure methane environments to obtain more conclusive results on potential hydrogen embrittlement issues. SoCalGas is working with DNV GL to test new pipe, including X70 that is relatively high tensile strength and represents less than 1% of the SoCalGas high pressure system and has the highest likelihood of embrittlement impact. SoCalGas and DNV GL will also test

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[18] EPRI, Quick Insights: Safety Considerations of Blending Hydrogen in Existing Natural Gas Networks (Sep. 6, 2019), *available at* https://www.epri.com/research/products/000000003002017253.

existing pipe of lower tensile strength common to the Joint Utilities' systems, to have a robust understanding of how their systems will respond to blended hydrogen.

B. Storage Facilities

Existing natural gas infrastructure in California utilizes depleted oil and gas reservoirs to store and withdraw natural gas, as required to meet customer demand and promote resiliency. The interaction of underground storage materials, including the natural rock formations, with a hydrogen-natural gas blend will need to be evaluated to determine the feasibility of utilizing existing utility-owned and independent storage fields for blended hydrogen-natural gas storage. Underground storage of hydrogen is being considered to leverage excess solar power generated in California. Pure hydrogen underground storage is not possible in depleted oil and gas reservoirs, because residual water, oil, and gas will remain - the goal is to determine what percentage of blended hydrogen can be safely stored. Pure hydrogen underground storage in salt caverns is a known practice that exists today; however, salt caverns are not present in California. Storing a blend of hydrogen and natural gas in depleted oil and gas reservoirs has more complex considerations than salt caverns, which are discussed below.

The Storage Integrity Management Programs of SoCalGas and PG&E and Independent Storage operators will need to be modified to address hydrogen storage if storage of hydrogen blends is determined feasible. Some research indicates that shallow reservoirs operated at lower pressure (less than 1200 psig) may be compatible with blended hydrogen storage.[19] Additional research will be required to determine whether the technical parameters of such studies are applicable to any existing storage fields in California.

The compatibility of wellbore materials, aboveground equipment, and well construction methodologies will also require further investigation or research. Underground Gas Storage Regulations put in place in October 2018 by the California Geologic Energy Management Division (CalGEM) may lend towards safe implementation of hydrogen blending, which is discussed further below. The technical consensus is that each underground storage facility needs to be studied individually to determine whether any percentage of hydrogen can be blended into the respective reservoirs. It is also critical to determine the compatibility of storage facilities

[19] Anna S. Lord, Sandia National Laboratories, Overview of Geologic Storage of Natural Gas with an Emphasis on Assessing the Feasibility of Storing Hydrogen (2009), *available at* https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2009/095878.pdf.

with hydrogen since they are currently interconnected with the natural gas pipeline system, thus, blended hydrogen transported in the system could enter the storage facilities in the current configuration. Until such considerations are addressed, injection of hydrogen into the vast majority of the Joint Utilities' gas transmission network cannot occur.

1. Materials

The materials considerations for storage are similar to other parts of the natural gas infrastructure. As noted above, steel alloy components (present at the storage facilities – both aboveground piping and equipment, and the wellbores) may be susceptible to the phenomena of hydrogen embrittlement and hydrogen-induced cracking.

Tubing in the storage wells tends to be of higher tensile strength, which increases susceptibility to embrittlement. Due to the Storage Integrity Management Programs required by CalGEM, there are already existing mitigations for natural gas storage including: tubing-only flow that isolates the blended hydrogen from the wellbore casing; and frequent inspection intervals that detect impacts to wellbore integrity, allowing for replacement of materials – including the opportunity to replace with hydrogen compatible materials, including, but not limited to, hydrogen resistant alloys. The Storage Integrity Management Programs of SoCalGas and PG&E, and Independent Storage operators will need to be modified to address hydrogen storage if storage of hydrogen blends is determined feasible.

Elastomer integrity in the presence of blended hydrogen, also noted in the materials section, is likewise a consideration for storage infrastructure. Elastomers are found in tubing packers and serve as seals. Elastomer research will also need to evaluate downhole tubing packers and seals. Replacement of tubing packers and seals with hydrogen compatible materials may be required. The integrity of cement used to seal well casings is another consideration in the presence of blended hydrogen. The hydrogen dissolution processes can potentially diminish the sealing ability of the cement bond of gas storage wells.

The integrity and operation of downhole safety valves is another consideration in the presence of hydrogen-natural gas blends. Research is required to determine compatibility and ensure that such systems operate when required.

2. Aboveground compatibility analysis

The aboveground considerations are primarily related to compatibility of hydrogen with materials. As such, the same compatibility considerations mentioned above apply here.

Production equipment including tri-ethylene glycol dehydration and re-generation systems, metering equipment, measurement and control equipment, and injection/compression equipment are to be considered for compatibility of blended hydrogen.

3. Belowground compatibility analysis

The primary belowground considerations (excluding the wellbore discussed above) are as set forth below.

a) Caprock Seal

As with natural gas underground storage, a thick, impermeable caprock (the geologic unit above the storage reservoir, serving as a component of confinement for the gas) is one of the key considerations for successful underground storage of hydrogen. Hydrogen is a smaller molecule, so diffusivity of hydrogen through the caprock will need to be modeled; one study notes 1.5%-2% hydrogen lost to the caprock. Additionally, geochemical reactions, discussed below, may reduce permeability and porosity of the caprock, further reducing the risk of hydrogen migration. The primary recommended mitigation is to prioritize storage in reservoirs with thick, impermeable caprock (over 100 feet). If a storage facility is selected for hydrogen storage, then the regular inventory assessments should be utilized to determine if there is any gas loss. If there is gas loss, then review can be done to determine if it is due to diffusion into the caprock (or reservoir fluid).

b) Hydrogen Separation and Hydrogen Partial Pressure

Research conducted to date indicates that hydrogen separation in storage is unlikely at any blending level due to the diffusivity of hydrogen, natural reservoir convection, and mixing dynamics from injection and withdrawal operations.[20] The Joint Utilities will need to conduct further modeling for each reservoir to confirm this research.

As hydrogen is blended into natural gas, the storage capacity of the reservoir is reduced. As the percentage hydrogen blend increases, so does the reduction in capacity (i.e., for the same pressure, a reservoir can store a larger quantity of natural gas and a lower quantity of blended hydrogen). There is no additional research needed at this time, only an awareness to maintain

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[20] Netherlands Enterprise Agency, The Effects of Hydrogen Injection in Natural Gas Networks for the Dutch Underground Storages: Final Report (2017), *available at* https://www.rvo.nl/sites/default/files/2017/07/The%20effects%20of%20hydrogen%20injection%20in%20natural%20gas%20networks%20for%20the%20Dutch%20underground%20storages.pdf.

existing maximum operating pressure despite the decrease in gas storage capacity. The energy content of hydrogen–natural gas mixtures depends on the hydrogen content.

c) Microbial Response to Hydrogen

A Dutch study[21] suggested that with a 10% hydrogen blend, microbes within the storage reservoir may begin to consume hydrogen in the presence of trace components such as carbon dioxide and sulfur. The specific reservoir fluid must be sampled and tested to determine the reactions that will occur. These potential reactions include hydrogen loss, reservoir plugging, hydrogen sulfide production, bacterial growth, and methane production. These reactions are reservoir-specific.

d) Geochemical Reactions

Mineralogical changes may occur in the presence of hydrogen. Due to the complexity of mineral deposits in porous media reservoirs, introducing hydrogen in the reservoirs may cause undesirable geochemical reactions with reservoir minerals to produce adverse effects such as plugging, which would reduce permeability and promote formation of hydrogen sulfide. At the same time, hydrogen may react with the minerals of the sealing caprock, which is the main sealing mechanism for oil and gas reservoirs, causing dissolution of caprock and diminish sealing ability. Early studies[22] are conflicting as to whether hydrogen will impact mineralogy, or have little effect, and results show it is highly dependent on rock type. Similar to the microbial impact and mitigation, each reservoir needs to be studied to determine impact; for example, reservoirs and caprocks with carbon or sulfur bearing rocks will react, whereas iron bearing rocks are more stable.

C. End User Considerations

1. Operational Impacts on Natural Gas Appliances

Gas appliances that were designed for natural gas use need to be evaluated with hydrogen blends to determine if any performance, safety, and combustion issues will arise due to the difference in properties between hydrogen and natural gas. Methane is the primary component of natural gas. Compared to methane, hydrogen has a higher flame speed and adiabatic flame

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[21] *Id.*

[22] Alireza Ebrahimiyekta, Characterization of geochemical interactions and migration of hydrogen in sandstone sedimentary formations: application to geological storage (July 2017), *available at* https://www.researchgate.net/publication/323334825_Characterization_of_geochemical_interactions_and_migration_of_hydrogen_in_sandstone_sedimentary_formations_application_to_geological_storage.

temperature, smaller molecular size, wider flammability limits in air, and lower minimum ignition temperature.[23] Gas interchangeability indices such as flame lifting (which can lead to flame out or increased carbon monoxide), flashback (which can cause equipment damage), and yellow tipping (which can lead to increased carbon monoxide and/or exhaust restriction), should be evaluated. However, interchangeability studies performed recently indicate that gas appliances should be able to tolerate 5% or more hydrogen without any difficulty.[24]

In 2014, SoCalGas tested eleven natural gas appliances and burners with hydrogen blends containing up to 20% hydrogen for any safety or performance impacts. The equipment tested included water heaters, furnace, target type pilots, and residential and commercial cooking equipment. Test results suggested that 5% hydrogen does not cause flame, combustion stability, or safety issues. At 10% and 20% hydrogen, some burners exhibited noticeable changes in flame structure. The emissions results indicated that flame lifting was occurring but was not directly observed. In addition, there was some concern regarding low thermal output since hydrogen has approximately one-third the volumetric energy content of methane.[25] The hydrogen-natural gas blends supplied to the appliances sometimes had a higher heating value (HHV) lower than SoCalGas Rule 30 minimum specifications (HHV of 990 Btu/scf and Wobbe index of 1279 Btu/scf [26]). The Wobbe Index was usually above the SoCalGas Rule 30 minimum except for some 20% hydrogen blends. In general, it was found that the Wobbe index was a stronger predictor of flame stability than HHV. As more hydrogen was added, water heaters and the commercial grill exhibited decreases in nitrogen oxide (NOx) emissions. For other appliances, NOx emissions were mostly unaffected.

For future testing, it is recommended that new appliances are tested using the lowest Wobbe Index gas as a baseline and that detailed leak tests are conducted to determine if hydrogen increases leak rates in appliances and appliance components. It is also recommended that there be an evaluation of issues with the potential additional condensation formed as a

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[23] Melaina, *supra*.

[24] Range of Acceptability for Natural Gas Equipment, NYSEARCH Range Tool, *available at* https://www.nysearch.org/apps/gix.

[25] Ulf Bossel & Baldur Eliasson, Energy and the Hydrogen Economy (2018), *available at* https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf.

[26] SoCalGas Rule 30: Transportation of Customer-Owned Gas, SoCalGas (2014), *available at* https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf. (note: current 2020 minimum HHV is 970 Btu/cf).

combustion byproduct. Since most testing to date has focused on residential appliances, more commercial equipment should be tested in the future.

The Joint Utilities funded and participated in the development of NYSEARCH's Range of Acceptability for Natural Gas Equipment (RANGE) tool. It is a spreadsheet-based, interchangeability model designed to predict the performance of in-service residential appliances when new gas supplies are used. Since its initial development, this model has been updated to include the impacts of blending hydrogen into natural gas by leveraging previously generated burner test data. The RANGE tool predicts the impacts of hydrogen blending on the likelihood of flashback occurring and the reduction of heat output.

The effects of hydrogen and natural gas blending have been considered in Europe through several projects. Some of these projects have been completed, and some are in progress. The projects used various methodologies and parameters. Below are brief summaries of these efforts:

- THyGA (Testing Hydrogen Admixtures for Gas Appliances) launched in early 2020 with a mission to "close knowledge gaps regarding hydrogen-natural gas blends, to identify and recommend appropriate codes, standards that should be modified or adapted to answer the needs for new and existing appliances."[27] This project is led by French utility Engie and will be completed by a consortium of companies from six European countries. The high-level approach of THyGA is to perform a thorough review of the existing European appliance portfolio, identify and test the impacts of hydrogen-natural gas blends on approximately 100 appliances that are representative of the entire portfolio, develop an appliance certification protocol for various levels of blending, and make recommendations to various stakeholders in the appliance industry.
- In 2017, DNV GL and the University of Groningen developed a method for determining hydrogen blending limits for customer appliances without the need for physical testing.[28] It was found that the maximum blend is highly dependent on the composition of natural gas. The limiting performance factor varies

[27] THyGA, Objectives of the Project, *available at* https://thyga-project.eu/about-thyga/.
[28] Harmen de Vries et al., The impact of natural gas/hydrogen mixtures on the performance of end-use equipment: Interchangeability análisis for domestic appliances, 208 Applied Energy 1007, 1019 (2017).

depending on the type of appliance: flashback for fuel-rich appliances such as cooking burners and reduced thermal input for lean-premixed appliances.

- HYREADY, led by DNV GL, comprises an international group of utility members, including PG&E and SoCalGas.[29] It is focused on studying existing knowledge, not testing, and covers the impacts of hydrogen blending on many parts of the natural gas chain (including end-use) over a range of blend ratios. The intent is to apply an interchangeability approach to determine allowable hydrogen blends at several natural gas compositions, while also considering the cost-benefit of replacing the most critical appliances that would allow for a higher hydrogen limit.

2. Emissions Impacts on Natural Gas End-User Equipment

A hydrogen-natural gas blend may yield higher NOx emissions than natural gas because hydrogen burns faster than natural gas, which increases combustion temperatures and reduces ignition lag. Previous end-use equipment testing completed by SoCalGas (referenced in the Operational Impacts on Natural Gas Appliances subsection above) yielded inconclusive emissions results, therefore, additional emissions testing should be completed with natural gas end-use equipment operating with hydrogen blends.

To address this knowledge gap, SoCalGas is supporting a Gas Technology Institute (GTI)-led project on hydrogen impacts on residential and commercial combustion equipment. This study will focus on emissions, efficiency, and performance of various common appliances in the residential and commercial sectors and will provide design guidance to manufacturers for lowering NOx emissions. This project is estimated to be completed by end of 2020.

SoCalGas is also testing common residential and commercial natural gas equipment (e.g., water heating, space heating, and commercial cooking) with up to 30% hydrogen in natural gas. This testing will focus on safety, emissions, performance, and efficiency and will further address existing knowledge gaps. This project is expected to be completed in the first quarter of 2021.

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[29] DNV-GL, Get prepared for hydrogen addition to natural gas, get HYREADY!, *available at* https://www.dnvgl.com/oilgas/joint-industry-projects/gas-value-chain/hydrogen-addition-to-natural-gas.html.

3. Material Impacts on Components Downstream of Meter Set Assembly

Past and current studies[30] on end-use equipment focus on determining if there are any operational impacts or potential safety issues (e.g., emissions, efficiency, flame characteristics) with using hydrogen blends. The long-term material compatibility of appliances has not been studied and there exists a knowledge gap.[31] However, given that the pressures downstream of the meter set assembly are relatively low (e.g., SoCalGas standard residential delivery pressure is 8 inches of water column and core customers can request elevated delivery pressures up to 5 psig,[32] PG&E standard delivery pressure is 7 inches of water column,[33] and Southwest Gas standard pressure is 0.25 psig[34]), the potential risk of hydrogen embrittlement and/or increased damage to sealant materials for downstream components is expected to be low.[35,36]

Moving forward, the Joint Utilities plan to identify the materials used in common end-use equipment and further investigate material compatibility with laboratory testing and/or engaging with industrial partners or original equipment manufacturers (OEMs) to conduct research.

D. Feedstock Customers and Gas Quality

Feedstock customers (e.g., fertilizer plants, petrochemical facilities, metal forming and working, heat treating, aerospace, defense, fuel cells, etc.) may be impacted by fuel composition changes. In 2014, SoCalGas surveyed several feedstock customers to learn how hydrogen in the fuel can affect their processes. Some customers were concerned that the hydrogen concentration fluctuation would cause their product quality to be less consistent and impact their certifications (i.e., some products require a certain level of quality to achieve certification). Additionally, some customers may not have the necessary process monitoring and controls to adequately respond to fuel composition changes. The need and cost for hydrogen analyzers, equipment modifications for metal forming, testing and reprogramming of automation controls for heat

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[30] Examples include NYSEARCH RANGE, THyGA, NATURALHY, GTI, HYREADY.
[31] Melaina*, supra.*
[32] SoCalGas Tariff Rule 2: Description of Service, *available at* https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/02.pdf.
[33] PG&E Gas Rule 2: Description of Service, *available at* https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_2.pdf.
[34] Southwest Gas Rule 2: Description of Service, Southwest Gas, *available at* https://www.swgas.com/7200000201447/2020_CA-Entire-Tariff-for-Website-10-01-20.pdf.
[35] H. Barthélémy, Compatibility of Metallic Materials with Hydrogen: Review of the Present Knowledge, *available at* https://www.h2tools.org/sites/default/files/ICHS_import/1.4.66.pdf.
[36] Emily Ho, Elastomeric seals for rapid gas decompression applications in high-pressure services (2006), *available at* https://www.hse.gov.uk/research/rrpdf/rr485.pdf.

treating, blending stations for large customers, and replacing/retrofitting piping (especially for pipelines with high pressure and temperature) still needs to be determined. Additionally, research needs to be done on various manufacturing methods to determine the critical level of gas composition changes.

A potential mitigative measure to address feedstock customer concerns include installation of hydrogen separation technology upstream of sensitive feedstock customer equipment but specific application of the technology must be further investigated.

1. Potential hydrogen separation technologies

Gas separation refers to the separation of blended hydrogen and natural gas that is mixed together in gas pipelines and not the generation of hydrogen from methane. The development of hydrogen separation technologies and bringing them to market is an important step for applications that require pure hydrogen (e.g., hydrogen fuel cell vehicles), only natural gas (e.g., CNG/LNG vehicles), or bypassing sensitive infrastructure or customers.

Research indicates that separation technologies are feasible and currently in development but are not yet widely and commercially available.[37] [38]

E. Natural Gas Vehicles (NGVs)

Since NGV engines and on-board fuel tanks were designed for natural gas use, the potential impacts of hydrogen need to be studied. Cummins Westport, the leading heavy-duty NGV engine manufacturer, has a 0.03% hydrogen limit for its on-highway spark ignition (SI) engines due to concern that hydrogen will deteriorate the platinum spark plug electrodes. SoCalGas, with support from PG&E, plans to conduct engine research with Cummins Westport and University of California, Riverside, to evaluate the impact of hydrogen blends on the performance and durability of a Cummins Westport NGV engine. Test data and engine modifications may justify updating the existing 0.03% hydrogen limit. This project is expected to begin in 2021.

Hydrogen embrittlement is a concern for on-board NGV compressed natural gas (CNG) tanks. High strength steels are commonly used for CNG tanks, and they are more susceptible to

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[37] Melaina, *supra*.

[38] Xiao Yuan Chen et al., Membrane Gas Separation Technologies for Biogas Upgrading, 5 RSC Adv. 24399, 24448 (2015), *available at* https://www.researchgate.net/publication/272423302_Membrane_gas_separation_technologies_for_biogas_upgrading.

hydrogen-assisted fatigue cracking than low strength steels. Sandia National Labs investigated if hydrogen-natural gas can be used in existing on-board NGV compressed natural gas (CNG) tanks.[39] There are four types of NGV cylinder designs, i.e., Types 1, 2, 3, and 4.

The Sandia National Labs study concluded that Types 3 and 4 cylinders can accept any amount of hydrogen. For Types 1 and 2 cylinders made of low strength steel with tensile strength less than 138 kilopounds per square inch (ksi) (950 megapascal (MPa)), any amount of hydrogen is acceptable. For Types 1 and 2 cylinders made of high strength steel with tensile strength greater than 138 kpsi (950 MPa), additional fatigue testing is required to determine a hydrogen limit.

A potential mitigative measure to address concerns for NGV engines and on-board fuel tanks is to install hydrogen separation technologies at CNG refueling stations. However, this is an expensive process which would be performed by the end user and would drive up their operating costs. Hydrogen separation technologies are discussed in detail in the following System Reliability section.

1. ASTM International CNG Motor Vehicle Fuel Specification

ASTM International is proposing to introduce a CNG motor vehicle fuel specification with a limit of 0.3% hydrogen.[40] This proposed specification is currently in balloting. The California Department of Food and Agriculture (CDFA) may potentially enforce this specification at commercial CNG dispensers, most of which are supplied with gas from either PG&E or SoCalGas.

In summary, just as with compressors, turbines, and engines, the Joint Utilities are making progress in increasing various hydrogen limitations for end users; however, the hydrogen limit would increase slightly. Further legislative or regulatory support and partnering with the various manufacturers and agencies would support the Joint Utilities' quest to maximize a hydrogen blending percentage.

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[39] B. Somerday et al, Hydrogen Effects on Materials for CNG/H2 Blends, International Hydrogen Fuel and Pressure Vessel Forum (2010), *available at* https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/ihfpv_proceedings.pdf.

[40] Allan Morrison, ASTM WK40094: New Specification for Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Used as a Motor Vehicle Fuel, ASTM International (2012), *available at* https://www.astm.org/DATABASE.CART/WORKITEMS/WK40094.htm.

IV. SYSTEM RELIABILITY

System reliability and providing service to utility customers is as key as safety and system integrity when planning to blend hydrogen into a natural gas infrastructure. Some considerations for system reliability include pipeline welding and inspections, facilities operations, and the backbone system supply and lower energy density of a hydrogen blend.

A. Operational Considerations for Steels in Hydrogen-Natural Gas Service

The following are operational practices that may be impacted by hydrogen blending. Mitigative efforts can include modifying these operations.

1. In-Service Welding and Hot Tie-Ins

In-service welding and hot tie-ins are frequently used to perform pipeline repair and replacement activities to minimize or avoid disrupting customer service. During in-service welding, hydrogen levels in the weld area must be strictly controlled to prevent possible hydrogen induced cracking (HIC) in the weld heat affected zone, which could ultimately develop into an uncontrolled gas leak in the pipeline. Presently, pipeline operators work to minimize and control weld hydrogen levels by ensuring base metal cleanliness and utilizing low hydrogen welding procedures. Embrittlement patterns and studies suggest the probability for weld cracks may be increased even with satisfactory low hydrogen welding processes when welding on pipelines that have been transporting a hydrogen-natural gas blend. Hydrogen charging (hydrogen bake-out) of the pipeline steel can also affect the weld quality and the ability to perform hot tie-in or in-service welds. Embrittlement, cracking and hydrogen charging are critical concerns during in-service welding where mitigative measures may be not be practical for this almost daily activity and would need to be addressed in establishing a hydrogen injection standard.

The minimum ignition energy for hydrogen is lower than natural gas. As such, the full safety impact for hot tie-ins while operating using hydrogen-natural gas blends is not known. Mitigative measures could require additional separation distances or increased utilization of double block-and-bleed procedures.

SoCalGas is currently participating in a Joint Industry Project (JIP), led by DNV GL, to study in-service welding while operating using hydrogen-natural gas blends. The Joint Utilities are also getting guidance from Hawaii Gas, a Hawaiian utility that has operated for decades with a 12% hydrogen blend in its pipeline.[41]

2. Cold Tie-Ins

Cold tie-ins are a method used to perform pipeline repair and replacement activities that require a section of the pipeline or pipeline facility to be shut down and evacuated prior to welding. The pipeline is isolated, evacuated, and purged to remove combustible levels of gas prior to starting work. There is no current knowledge that hydrogen would impact a cold tie-in; however, this process requires that valves utilized to isolate the pipeline segment provide gas tight seals. If gas tight seals are not obtained, the process must be abandoned and reverted to a hot tie-in.

3. In-Line Inspection (ILI)

ILI is a type of non-destructive testing that is commonly utilized to assess the integrity of gas pipeline systems. ILI tools, known as "smart pigs" or "pigging," travel inside the pipeline and are typically propelled by the gas flow. ILI tools locate and size volumetric defects (e.g., metal loss due to corrosion), deformation defects (e.g., dents, gouges, wrinkles, and buckles), and crack-like defects.

Limited research conducted to date indicates that ILI tools can be utilized in hydrogen-natural gas blends; however, further research is required to fully evaluate the impact (if any) on performing ILI inspections on pipelines with hydrogen blends.[42], [43]

4. Steel Valves

Valves installed on transmission stations and pipelines use stem seal designs made for natural gas. Some manufacturers have upgraded stem seal designs for use with other gases such as 100% hydrogen, but these valves are not currently installed. Additional research and testing are required to understand the risk of developing leaks when existing valves are subjected to

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[41] Hawaii Gas procures their natural gas from Naptha, which has approximately 12% hydrogen naturally occurring in it. *See* What is Hydrogen, Hawai'i Gas, *available at* https://www.hawaiigas.com/clean-energy/hydrogen/.

[42] Lise Lanarde, NATURALHY Report: Principles of Resource Allocation Relating to Pipeline Integrity Management (2008), *available at* http://66.39.116.196/docs/project_reports/Principles%20of%20resource%20allocation%20relating%20to%20pipeline%20integrity%20management.pdf.

[43] John Roubidoux et al, Measurement of the Effect of Magnetization on Hydrogen Cracking Susceptibility of Pipeline Steels, Colorado School of Mines (December 2010), *available at* https://www.bsee.gov/sites/bsee.gov/files/tap-technical-assessment-program//576aa.pdf.

hydrogen blends. Valves also have various components and instrumentation that would need to be assessed for compatibility with hydrogen.

B. Facilities (Regulator, Pressure Limiting, and Measurement Stations)

Since hydrogen will change the specific gravity, energy density, and composition of a natural gas blend, the operation and/or infrastructure of regulator and measurement stations will need to be modified for use with hydrogen blends. The following subsections detail current knowledge.

1. Regulator and Pressure Limiting Stations

Adding hydrogen to natural gas will lower the energy density of the gas blend, which will increase the required flowrate through regulator stations to deliver the same quantity of energy to customers. To compensate for the decreased energy density, the regulator stations would need to be evaluated to determine all the necessary upgrades required to meet the increased flow rates. In certain locations, the regulator station's outlet pressure may be increased as a potential mitigation, but only if the current setpoint is not close to the downstream system's maximum allowable operating pressure (MAOP). At many stations, the setpoint is just below MAOP, and raising it could increase the risk of an over-pressure incident. In addition, the additional gas flow needed may require supplement feed from other existing stations or new stations, which will require a more dynamic system model.[44]

For stations using relief valves for over-pressure protection, relief capacities may need to be reassessed. All official relief valve capacity calculations will need to be updated due to the new gas blend. Similar to the other systems discussed (e.g., PE, meter set assemblies, etc.), regulator station components and instrumentation will need to be assessed for compatibility with hydrogen. Additional investigation is needed to determine the effects on station pressure regulators and their ability to lock up and respond to downstream pressure changes, the limitations of set points to MAOP, the effects on dew point and temperature drop, and the extent of retrofits or replacements of the entire station or components within.

2. Measurement Stations

It is imperative for the Joint Utilities to be able to measure the blended gas at a predetermined location downstream of the Hydrogen Injection Station. For this reason, the Joint Utilities will need to design and build new measurement stations or modify the existing heating

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[44] See System Reliability, Backbone System Supply, *infra*, for further details on system capacity.

value measurement stations to measure the blended gas composition and volumes entering the pipeline. Furthermore, downstream large volume customers will be receiving a hydrogen-natural gas blend and must be notified of the composition or require changes to their gas composition analyzers. In addition, depending on the percentages of the hydrogen injection, downstream stations supplying gas to large volume non-core customers, may need to be modified to measure gas correctly. A technical, risk and cost-based study must be performed to determine the required level of modifications to the stations, and the effects of hydrogen-blended gas on the integrity of steel and the elastomers. Further modifications must be made to the heating value map and the therm-billing zones to ensure that correct heating values are used to calculate customer bills. These changes will require software modifications to the Joint Utilities' various gas flow monitoring systems.

a) Orifice and In-line Ultrasonic Meters

Orifice and in-line ultrasonic meters are recommended for custody transfer hydrogen blended natural gas measurement. Due to the presence of hydrogen, some common in-line ultrasonic meters used in the industry for natural gas measurement may not be capable of measuring hydrogen blended natural gas. An applicable specification describing gas constituents must be developed and communicated with the ultrasonic meter manufacturers in advance of the ultrasonic meter selection for new stations. For existing stations, the meter manufacturers shall also be contacted to confirm the suitability of the equipment. Detail specifications must be developed for design, modification, and installation of both orifice and ultrasonic custody transfer and operational meters.

b) Heating Value Measurement and Gas Analysis

Blending hydrogen into natural gas will decrease the specific gravity and heating value of the blended gas. To measure gas accurately, live gas analysis must be performed to determine the chemical composition, including the hydrogen concentration in the blend. The gas component concentration must be input into the flow computer to complete the gas measurement process.

SoCalGas is planning to evaluate two gas chromatographs capable of detecting and measuring hydrogen. Since heating value measurement devices approved by the California Public Utilities Commission (Commission) cannot analyze hydrogen in natural gas, SoCalGas has selected two gas chromatographs for evaluation. The devices that pass SoCalGas's evaluation will be submitted to the Commission for approval.[45] This project is estimated to be completed by end of the first quarter of 2021.

c) Flow Computers

Flow computers must be specified or modified for hydrogen blended natural gas for both ultrasonic meters and orifice meters. The flow computer manufacturer must confirm the accuracy of measurement for hydrogen blended natural gas, for both custody transfer and operational meters.

d) Piping Configuration

For ultrasonic meter installations, piping must be in accordance with the latest requirements of American Gas Association Report No. 9 (AGA-9), Measurement of Gas by Multipath Ultrasonic Meters. If the station consists of control valves, the piping configuration must be such that the ultrasonic noise generated by the control valve will not interfere with ultrasonic measurement. Provisions such as installation of blind tees, or special noise cancelling transducers must be used and communicated to the manufacturer prior to the selection of the meter and completion of the station modification or for new designs.

For orifice meters, new station provisions must be made to ensure a smooth flow profile. Additional piping diameters upstream and downstream of the orifice fitting must be included to reduce the swirl action. Furthermore, it is recommended to have a minimum of 13 diameters upstream and 4.5 diameters downstream of the orifice fitting. Conditioning plates or tubes must be installed upstream of the orifice fitting.

C. Compressors, Turbines, and Engines

Gas compression equipment is utilized on high pressure systems to maintain system throughput. Such equipment represents a significant portion of the total cost of a natural gas network and is a critical component of the California hydrogen strategy. Hydrogen compatibility studies must evaluate: the suitability of hydrogen blends as a fuel source; compatibility of hydrogen blends on each component of the equipment (high strength steels, elastomers, and seals); impacts on emissions associated with new/varying fuel composition; impacts on equivalent energy throughput; impacts on the maintenance and life cycle of the equipment; and impacts on the safe and reliable operation of the equipment. Note that the Gas for Climate

[45] General Order 58-B requires devices measuring heating value of gaseous fuels for billing purposes be approved by Energy Division.

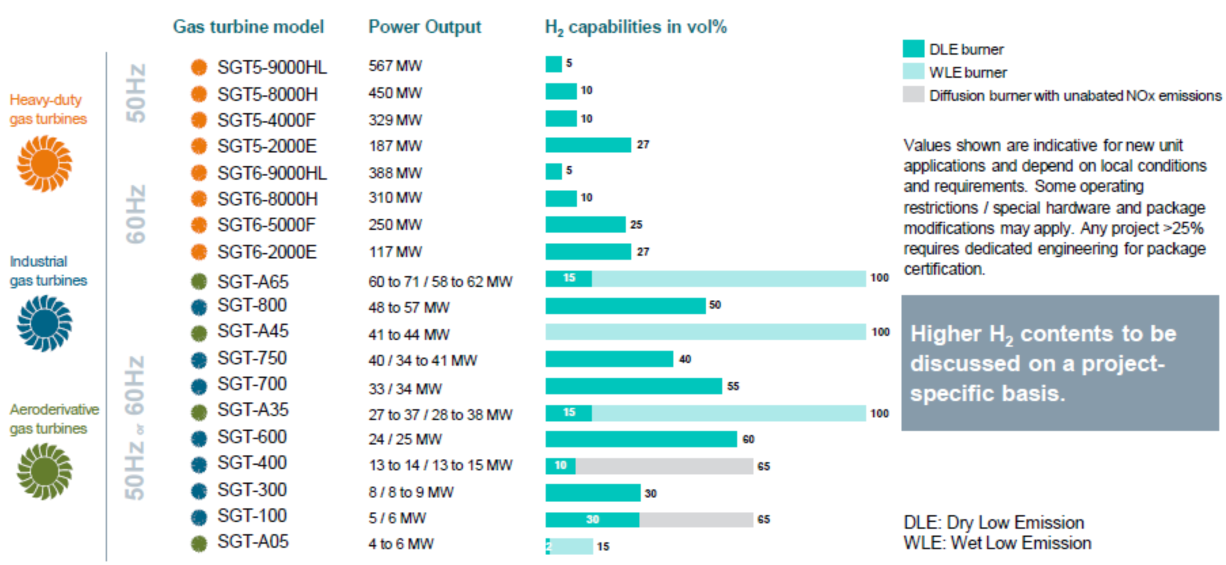
consortium's European Hydrogen Backbone report does not anticipate converting any existing natural gas compression equipment to hydrogen service.[46]

There are new commercially available gas compressors, turbines, and engines that can accept fuel with increasing concentrations of hydrogen. The tables below show ranges of hydrogen compatibility for various new gas turbines. Manufacturers of engines and compressors have similar specifications which provide ranges of hydrogen compatibility; however, some compression manufacturers continue to exclude hydrogen blends from their specifications. Many manufacturers report that existing compression equipment can be upgraded for hydrogen-natural gas service; however, such upgrades require site-specific evaluations of the equipment and maintenance history. Other manufacturers of existing compression equipment are no longer in business, and conversion of such equipment will require additional research.

Figure 2 and Table 1 list the range of hydrogen compatibility for various turbine manufacturers.

Figure 2

Hydrogen Limits for Various Siemens Gas Turbine Models[47]



[46] Anthony Wang et al., Guidehouse, European Hydrogen Backbone: How a Dedicated Hydrogen Infrastructure Can Be Created (July 2020), *available at* https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/.

[47] John Marra, Siemens, Siemens Perspective on Future Hydrogen Fuel (Feb. 26, 2019), *available at* http://energyhuntsvillesummit.com/wp-content/uploads/2019/03/5_Energy-Huntsville-Hydrogen-Final-Marra.pdf.

Table 1

Maximum Allowable Hydrogen Concentration by Turbine Manufacturer

Manufacturer	**Hydrogen Limit**
General Electric	5%[48]
Solar Turbines	4%[49]
Capstone Turbine	1%[50]

SoCalGas is partnering with University of California, Irvine (UCI), and Capstone Turbine to demonstrate low emissions operation of a hydrogen-tolerant microturbine-based combined heat and power (CHP) system. Previous work has been done by UCI under funding by the California Energy Commission (CEC) to adapt a commercial Capstone Turbine C-60 Microturbine Generator (MTG) to operate on 100% hydrogen, but the emissions levels were higher than desired. Subsequent work partially supported by Capstone Turbine and the DOE led to the evolution of flashback resistant injectors as a key component necessary to operate the engine on hydrogen, but extensive engine testing was not conducted. With this current project, additional injector modification and possible combustion liner modifications to attain desired low emissions operation will occur.

For reciprocating internal combustion engines, a potential concern when operating with hydrogen-natural gas blends is knock, which is caused by autoignition of unburned fuel-air mixture before the propagating flame in the cylinder.[51] Knock can lead to damage of the engine's cylinder walls and pistons. At high hydrogen concentrations, engines may experience knock. To prevent knock, the engines can be de-rated, i.e., operate at a horsepower that is lower

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[48] Dr. Jeffrey Goldmeer, General Electric, Power to Gas: Hydrogen for Power Generation (Feb. 2019), *available at* https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf.

[49] Solar Turbines, ES 9-98: Fuel, Air, Water (Or Steam) & Compressor Cleaning Fluids for Solar Gas Turbine Engines (2020).

[50] Information from Capstone Turbine.

[51] Sander Gersen et al., Physicochemical Effects of Varying Fuel Composition on Knock Characteristics of Natural Gas Mixtures, 161 Combustion and Flame (Issue 10) 2729, 2737 (2014), *available at* https://www.sciencedirect.com/science/article/abs/pii/S0010218014000996.

than their rating.[52] The upper range of hydrogen for engines, whether rich or lean burn, will frequently be set by the ability to achieve NOx compliance as described below.

For both turbines and engines, since controls are optimized for a specific range of fuel heating value and relative density, fluctuating hydrogen content in the fuel supply would be an operating issue. When operating with hydrogen blends, it will be necessary to ensure a consistent hydrogen supply to maintain gas blend composition. An alternative is to develop controls and sensors that would allow for variable fuel compositions.

For compressors, increased leakage is a potential concern when hydrogen is injected into the natural gas supply. Due to the small molecular size of hydrogen, leak rates and crankcase vapors may increase. To reduce leakage, it is recommended to use a double distance piece for gas leakage control. A distance piece isolates the crankcase and the compressor cylinder from each other, and it can be plugged, purged, vented, or pressurized.

Mitigation strategies include upgrade of existing compression equipment; installation of supplemental gas compression equipment; and/or replacement of existing gas compression equipment. In some cases, it is anticipated that the decreased energy density of hydrogen will require consumption of higher volumes of fuel to maintain an equivalent energy throughput. Additional challenges can arise if emissions from gas compression exceed existing air permit requirements. The complexities and costs associated with compression of hydrogen-natural gas blends will require each Utility to develop a comprehensive strategy to address compression on high pressure piping systems.

1. Hydrogen Impacts on Emissions

For both turbines and engines, a hydrogen-natural gas blend will yield higher NOx emissions than natural gas because hydrogen burns faster and hotter than natural gas. In engines, the faster burn reduces ignition lag and increases combustion temperatures. To counteract the faster ignition caused by hydrogen, the ignition timing on an engine can be delayed. With turbines, the manufacturer will have to change air-fuel ratio (AFR) control algorithms and may have to include additional controls to maintain NOx compliance. These changes are especially challenging below 50% load, where Dry Low NOx combustion turns off or phases out. Maintaining proper combustion across the load range of a turbine is difficult. For turbines and

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[52] *Id*.

lean burn engines with Selective Catalytic Reduction (SCR) systems, the increase in NOx will require additional ammonia to treat and reduce the NOx.

For lean-burn engines, the increase in NOx can be prevented if the air-fuel ratio and ignition timing are adjusted.[53] Given that existing air-fuel ratio controllers may not operate as expected if hydrogen is in the fuel, more advanced controller technologies need to be researched (e.g., continuous combustion chamber pressure monitoring (CPM), ion sensing, NOx process analyzers or sensors, Trapped Equivalence Ratio (TER)). This may require modeling, laboratory tests, and field testing, which will be costly.

For rich-burn engines with Non-Selective Catalytic Reduction (NSCR) systems, previous laboratory testing suggests that emissions can remain in compliance with California air quality requirements if the engine is tuned carefully.[54] However, more advanced systems will be needed to accommodate blends with higher hydrogen content. These advanced systems and controls do not exist and will need to be developed.

Equally important are the range of hydrogen concentration the engine or turbine will burn, and still expected to operate with 100% natural gas, and the rate of change in hydrogen concentration. The turbine or engine control system may need to be redesigned to adjust to variable fuel composition. Some machine manufacturers have defined hydrogen limits within their current specifications; other manufacturers have not yet defined their hydrogen limits. The Joint Utilities are partnering with some manufacturers to explore increasing the specification limits in order to allow an increase in hydrogen content. However, if the manufacturer is not willing to explore hydrogen or altering their design or specification, the set hydrogen cap will be a consideration for developing the hydrogen injection standard.

2. Increased Flow Rates and Compression Horsepower

Because hydrogen has approximately one-third the volumetric energy content of methane,[55] a higher volumetric flow is required to deliver the same amount of energy as natural gas. Centrifugal compressors may need to add more compression stages in order to achieve a

[53] Antonio Mariani et al., A Review of Hydrogen-Natural Gas Blend Fuels in Internal Combustion Engines, Fossil Fuel and the Environment (2012), http://www.intechopen.com/books/fossil-fuel-and-the-environment/a-review-of-use-of-hcng-fuels-in-internal-combustion-engines.
[54] Colorado State University, Impact of H2-NG Blending on Lambda Sensor NSCR Control and Lean Burn Emissions, (2015).
[55] Bossel, *supra*.

higher volumetric flow rate, but a higher rotational velocity may affect the material integrity of the compressor.[56] Future equipment testing will be required to determine operational impacts.

Manufacturers' hydrogen limits may increase with further research to modify or develop more advanced hardware (e.g., flashback-resistant fuel injectors) and controls (e.g., air-fuel ratio control). Additional safety precautions can be taken such as installing hydrogen and fire detection sensors, removing ignition sources, and using stainless steel instead of carbon steel.

D. Backbone System Supply

The gas transported to the Joint Utilities via the interstate pipelines, as well as some of the California-produced gas, is delivered into the PG&E and SoCalGas intrastate natural gas transmission pipelines systems (commonly referred to as California's "backbone" pipeline system). Natural gas on the Joint Utilities' backbone pipeline systems is then delivered to the local transmission and distribution pipeline systems, or to natural gas storage fields. Some large volume noncore customers take natural gas delivery directly off the high-pressure backbone and local transmission pipeline systems, while core customers and other noncore customers take delivery off the Joint Utilities' distribution pipeline systems.

Preliminary results indicate that system capacity is impacted by the same percentage as heating value is impacted. Blending 10% volume of hydrogen in natural gas decreases the calorific value by some 7%.

With the forecast decline in annual and high-sendout day gas demand, the SoCalGas backbone and local transmission systems have sufficient capacity to accommodate expected levels of hydrogen blending. PG&E has multiple portions of its backbone and local transmission systems that are capacity constrained and will not have excess capacity to accommodate hydrogen blending in the near term.

1. Hydrogen Impacts on Energy Delivery

Injecting hydrogen into a natural gas pipeline will reduce the energy delivery capacity of the pipeline. Gas pipeline systems need to have sufficient capacity to meet the energy needs of the customers they serve. The Commission requires utilities to meet certain design day requirements on gas transmission and distribution systems. The amount of hydrogen injection into the system cannot be to the degree that it results in the inability to meet energy delivery commitments.

[56] Melaina, *supra*.

Preliminary storage analyses also indicate that the energy delivery capacity will decrease with the introduction of hydrogen. The Joint Utilities will have to ensure that any reduction in storage capacity will not result in supply shortfalls on the system. Independent Storage Providers (ISP) play a significant role in maintaining adequate supply and reliability on some systems. The Joint Utilities will need to work with these ISPs to address any issues they may have with hydrogen-blended gas.

Furthermore, the natural gas infrastructure grid allows for an upstream system to serve multiple downstream transmission and distribution systems. An upstream system is considered the feed source of a downstream system grid where there is a compressor, regulation or limiting station controlling the pressure differential between the two system. Each of these downstream systems could have different capacity requirements and varying degrees of being constrained. As a result, each of these systems may have a different level of hydrogen that they can accept. If hydrogen is injected into an upstream system, one would have to ensure that the hydrogen concentration delivered to each of the downstream systems is within acceptable limits for that system. Both the integrity of the pipeline and the energy needs of the customers must be considered.

2. Gas Quality and Composition Requirements

Some large customers may also have more stringent gas quality and composition requirements than typical customers on the gas system. So, in addition to ensuring there will still be adequate capacity on all the gas systems, there would need to be mechanisms or processes in place to assure that major customers on the system receive natural gas that is suitable for their operations.

If there are multiple hydrogen injection points on a system, the gas composition could potentially end up being very different depending on locations within the system. Given the dynamic flow patterns on some system and null points (locations of zero flow) that can change location, it may be challenging to manage the blending of various gas streams to ensure that all areas of the system stay within acceptable levels. This would need to be addressed in order to maintain reliable service and provide gas with consistent quality to customers throughout the system.

3. Variability Impacts with Hydrogen Injection

If the hydrogen blend is not consistent and predictable over time, the resulting fluctuation in system capacity may be a challenge to manage. In backbone systems, it is required to provide the market with reasonably accurate capacities so customers can manage their energy portfolios. If the hydrogen blend is constantly changing, it may be difficult to forecast system capacity for the market. It can be even more challenging if there are multiple hydrogen injection points and multiple blends on the system. A system or process to manage system capacity under varying hydrogen concentrations may be needed.

The same issues as described above exist for downstream local transmission and distribution systems. If the hydrogen blend fluctuates on these systems, the capacity on these systems will likely fluctuate with the blend. The Joint Utilities will need a way to make sure they can meet design day requirements even as the hydrogen blend and capacity changes. In addition, local transmission and distribution system flowrate have wide variations both within the day and throughout the year. For example, a summer demand is about 20% of the peak demand these systems are designed to meet. Winter system flows can be three to four times summer flows significantly impacting the challenges of managing an acceptable energy content throughout the year and within each day.

Another consideration is the reduced capacity due to reduced pressure or locking in a line for maintenance, inspection or other similar operational constraints. It is possible that when a hydrogen blend is injected that the Joint Utilities may experience more required downtime for critical pipelines due to more stringent inspection requirements and other factors cited in this section. Many gas systems already experience scheduled downtime annually due to ILI, repairs, hydrotests, new construction, pipeline retrofits, and replacements. Some of these scheduled downtimes can last for months and result in capacity constraints on the system. The Joint Utilities must obtain a strong understanding of the incremental line interruptions prompted by varying degrees of hydrogen blending to ensure we have adequate system reliability.

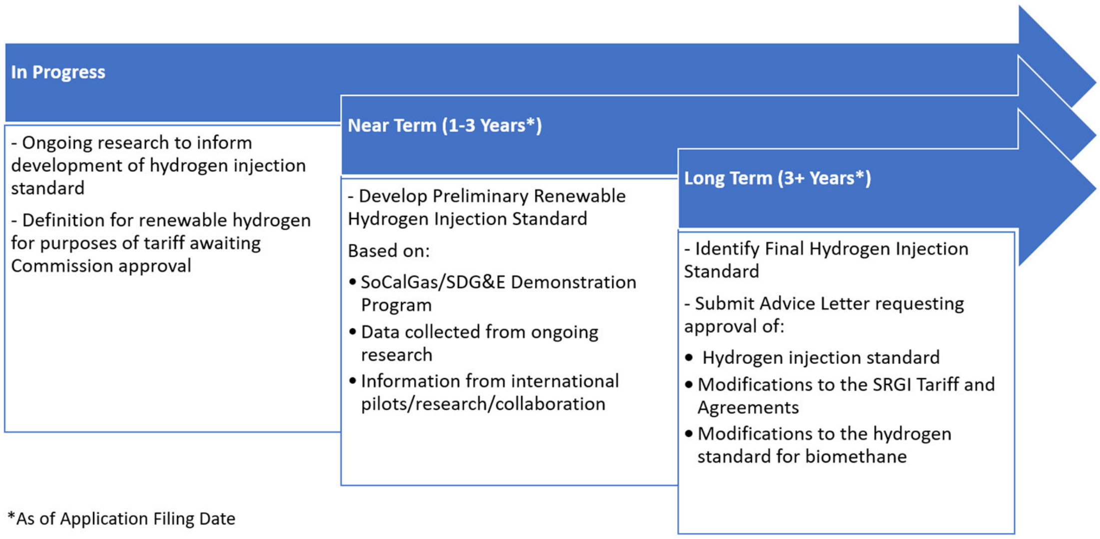
V. PROGRESSION

The Joint Utilities will prioritize safety as they pursue the additional research, studies and demonstrations with the goal of informing the development of a hydrogen injection standard which will allow hydrogen blending within a natural gas infrastructure in the near future. This testimony attests to the safety, system integrity, and reliability considerations for hydrogen injection into an existing natural gas system and incorporates best practices of the Plan-Do-Check-Act model described in Chapter 1 in order to control and implement a four-stage approach for continually improving processes, and for resolving issues.

The Hydrogen Injection Progression figure below (Figure 3) outlines activities currently in process and the need for ongoing research and demonstration projects to inform the development of a hydrogen injection standard. Various technical and engineering aspects identified in this testimony need to be addressed and resolved in order to achieve a hydrogen blending injection standard with defined percentages within the various asset families and technical categories. It is possible when a study or demonstration project is completed, that additional research will be required in order to identify a set hydrogen blending percentage.

Figure 3

Hydrogen Injection Standard Progression



VI. CONCLUSION

Though the Joint Utilities have made significant progress through literature reviews, research, studies and industry partnership, more exploratory research is required. Specifically, the identified demonstration projects in the SoCalGas and SDG& Service Territory (Chapter 3) and addressing the diversity, complexity and variability of a utility-specific natural gas infrastructure is a priority and must be completed as a core requirement in developing a hydrogen injection standard. The Joint Utilities have addressed how it will approach Safety, System Integrity, and Reliability through further study and investigation in order to confirm a strategy for hydrogen blending which includes mitigative measures. The impact of hydrogen blending on safety, embrittlement, leakage, material and equipment compatibility and other technical areas described in this chapter must be fully understood and addressed. The Hydrogen Blending Demonstration Program (Chapter 3) takes this first operational step of hydrogen blending within isolated and controlled system in the distribution and transmission grids. The Joint Utilities are committed to accomplishing the technical recommendations set forth in this chapter.

This concludes our jointly prepared direct testimony.

VII. QUALIFICATIONS

Kevin Woo

My name is Kevin Woo. I am employed at SoCalGas as a Team Leader in the Gas Engineering organization. Specifically, I oversee the Applied Technologies team at the Engineering Analysis Center facility in Pico Rivera, California and have held this position since March 2018. Prior to this I have held positions within SoCalGas including Pipeline Integrity Management, Distribution Planning and Engineering, and other engineering roles at the Engineering Analysis Center. I have been employed at SoCalGas since 2006. I hold a Bachelor of Science degree in Aerospace Engineering from University of California Los Angeles. I have not testified previously before the Commission.

David McQuilling

My name is David McQuilling. I am employed at Pacific Gas and Electric as Chief Corrosion Engineer on the Gas Transmission Integrity Management Team. Prior to joining PG&E in August 2015, I was the Senior Manager of Corrosion Control for Energy Transfer in Houston, Texas, responsible for all aspects of the Corrosion Control Program for a 71,000-mile network of natural gas, crude oil, natural gas liquids, and refined product pipelines. I have a Bachelor of Science degree in Electrical Engineering from Louisiana Tech University. I represent PG&E on the Pipeline Research Council International's Corrosion Control Committee and serve as the Vice Chair – External Corrosion Lead. I am a member of National Association of Corrosion Engineers (NACE) International, where I have been an active participant on multiple technical committees that develop NACE Standards. I also represent PG&E on the American Gas Association corrosion operating committee and on corrosion and integrity initiatives for the Interstate Gas Association of America.

Kevin Lang

My name is Kevin M. Lang and I am the director/Engineering Services for Southwest Gas. I direct and coordinate engineering and technical support to five operating divisions for pipeline safety code compliance; right-of-way and land rights acquisition and maintenance, material specifications and approval; environmental policies and procedures; proper energy measurement; pipeline cathodic protection; technical support of the Supervisory Control and Data Acquisition (SCADA) system; project design review; hydraulic modeling support; and the training and qualification of technical services personnel. I previously oversaw the Company's Distribution Integrity Management Program (DIMP) and laboratory services under the same capacity.

I joined Southwest Gas in 2003 as an engineer in Victorville, CA. I was subsequently promoted to distribution engineer in 2005, supervisor/Engineering in 2006 and manager/Engineering in 2007. During this period, I oversaw the design of transmission and distribution facilities for new business, franchise and system reinforcements; PVC pipeline replacements; pipeline safety code compliance; MAOP studies and requalification programs; and preparation of short and long-term capital budgets.

I was promoted to director/Gas Operation Support Staff in 2011 where I directed the Company's technical skills training, Operator Qualification (OQ) training and testing, tool and equipment evaluations, operations-related procedures manuals, Incident Command System training and operation of the Emergency Response Training Facilities in Tempe and Las Vegas. I was subsequently promoted to director/Engineering Services in November of 2012. I hold a Bachelor of Science degree in Mining Engineering from Virginia Tech and am a registered Professional Engineering in the state of Nevada with a proficiency in Civil Engineering. I currently serve on the American Gas Association's Operations Safety Regulatory Action Committee.