SHASTA

Subsurface Hydrogen Assessment, Storage, and Technology Acceleration - 2024 Technical Workshop

April 3 2024

Wyndham Grand Hotel in Pittsburgh, PA.

TIME	PRESENTER	ORGANIZATION	TOPIC
8:00 am	Evan Frye/Timothy Reinhart	FECM	Welcome and program comments
8:05 am	Josh White	SHASTA-LLNL	SHASTA Project Overview
8:15 am	Leon Hibbard	SHASTA-PNNL	Regional Case Studies for H_2 Storage
8:35 am	Shruti Mishra/Gerad Freeman	SHASTA-SNL, PNNL	Local and Regional-Scale Technoeconomic Analysis
8:55 am	Julia Camargo	SHASTA-PNNL	Reservoir Simulations and Code Comparison
9:15 am	Ryan Haagenson	SHASTA-PNNL	Core Flooding Experiments and Simulations
9:35 am	Djuna Gulliver	SHASTA-NETL	Microbial Characterization
9:55 am	BREAK		Break
10:15 am	Angela Goodman	SHASTA-NETL	H_2 Wettability, Permeability, and Diffusion
10:35 am	Gaby Davilla/Guanping Xu	SHASTA-LLNL, SNL	Geochemical Impacts of Subsurface H_2 Storage on Reservoir and Caprock Characteristics
10:55 am	Barbara Kutchko	SHASTA-NETL	Well Integrity
11:15 am	Christopher San Marchi	SHASTA-SNL	Gaseous Hydrogen Embrittlement of Metals for H_2 Storage
11:35 am	Ruishu Wright	SHASTA-NETL	Real-time Sensor Technologies for Hydrogen Subsurface Storage
11:55 am	Mathew Ingraham	SHASTA-SNL	Salt Mechanics
12:15 pm	LUNCH		LUNCH
1:15 pm	Melissa Louie/Tom Bushcheck	SHASTA-SNL, LNNL	Risk Mitigation, Operations, and Recommended Practices
1:35 pm	Franek Hasiuk	SHASTA-SNL	H_2 Field Scale Test Plan
1:55 pm	Serge Van Gessel	Task 42	Task 42: IEA TCP
2:15 pm	Todd Deutsch	NREL	An overview of the pipeline blending CRADA - A Hyblend Project
2:35 pm	Carolyn Descoteaux	PRCI	PRCI - Emerging Fuels Institute Update
2:55 pm	Peter Warwick	USGS	Overview of Energy Storage & Hydrogen Research at the U.S. Geological Survey
3:15 pm	BREAK		BREAK
3:30 pm	Ning Lin	GEOH2	Screening and Valuation Frameworks: Paving the Way for Viable Hydrogen Storage Solutions with $GeoH_2$
3:50 pm	Scyller Borglum	WSP	Boots on the Ground: Practical Application for Storing Hydrogen
4:10 pm	Shadi Salahshoor	GTI	Subsurface Storage Technological Advancements & Innovation for Hydrogen: SUSTAIN H_2
4:30 pm	Mohamed Mehana	LANL	Overview of LANL's Underground Hydrogen Storage Projects and Future Outlook
4:50 pm	SHASTA PIs	SHASTA	Wrap-up/Questions
5:00 pm	Adjourn		Adjourn

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Subsurface Hydrogen Assessment, Storage, and Technology Acceleration

2024 Technical Workshop

Resource Sustainability Project Review Meeting

April 03, 2024 – Pittsburgh, PA

The following bullets summarize the top 20 research highlights of the stakeholder workshop, in the order presented rather than by degree of relative importance. This list is followed by a more detailed summary of each speaker's presentation.

1. A methodology for assessing hydrogen storage opportunities using two case studies, the first in Cook Inlet Alaska and the second in Pennsylvania, has been demonstrated. In Alaska, seven pools were identified as suitable. In Pennsylvania, some formations (Oriskany, Elk) exhibit properties that might be favorable for hydrogen storage.

2. A system of equations representing subsurface system configurations coupled with a cost/revenue model is being used to identify relevant site screening criteria. Hydrogen demand at the county level was modeled across a northern Appalachian study region, to understand how much hydrogen storage would be needed, the costs of storage at higher priority storage locations, and key factors impacting levelized costs.

3. Most commercial compositional simulators do a good job of handling hydrogen mixtures, except for viscosity. The Lohrenz-Bray Clark model has been modified to address this shortcoming and an updated simulator used to model a synthetic hydrogen storage reservoir and learn the key factors in ensuring a stable hydrogen cap.

4. Core flooding experiments and simulations reveal that higher hydrogen injection rates speed up hydrogen breakthrough, higher permeability sandstones see quicker breakthrough, gravity override can be a factor due to density differences, and heterogeneity may impact flow.

5. With respect to microbial characterization in hydrogen storage reservoirs, sampling and DNA analysis revealed that biota from different sites can be different both in terms of the microorganisms represented and the level of diversity (e.g., iron mobilizing organisms versus sulfur reducing and acetate producing organisms), despite being relatively close spatially. One can expect a relatively high abundance of organisms with the potential to consume hydrogen and the rate will be most important during the 1-to-3-day timeframe when injecting hydrogen.

6. Laboratory tests have shown that upon injection of hydrogen, reservoir rocks will remain water-wet and the rate of hydrogen movement through shale caprock is very slow.

7. A discussion of geochemical impacts on subsurface hydrogen storage and related reservoir and caprock characteristics. Introducing hydrogen into a reservoir rock system can cause chemical disequilibria leading to hydrogen loss, production of other gases (like H_2S), and mineral dissolution/precipitation (which can in turn lead to rock property changes that can impact hydrogen injectivity and migration).

8. Hydrogen is relatively non-reactive with reservoir rock minerals. However, significant amounts of hydrogen can be adsorbed and retained by clay minerals like k-montmorillonite and nearly 23% can be irreversible. However, hydrogen adsorption capacity decreases after the initial adsorption. After hydrogen adsorption, the pore microstructure changes; pore volume shrinks and pore size decreases.

9. Experiments have not revealed any indications of discernable changes in cement chemistry or microstructure from hydrogen exposure. Pozzolan cement appears to adsorb less hydrogen than Class H cement, but hydrogen adsorption is very low. The presence of hydrogen will have little to no influence on wellbore cement integrity in a subsurface hydrogen storage reservoir.

10. NETL's distributed optical fiber interrogator systems, developed for monitoring pipeline and wellbore conditions for leaks, can provide a solution to the lack of commercial hydrogen sensors compatible with mixed methane/CO_2/hydrogen/water environments at hydrogen storage conditions. NETLs sensors are compatible, and their sensing capability is not affected by methane or biotic activity across a range of hydrogen concentrations. Plans are to optimize the sensor, ruggedize it, completely calibrate it at HT/HP conditions and then deploy it in actual wellbore locations to validate it under controlled conditions.

11. Testing of core samples from salt formations revealed that the presence of interbeds can cause significant increase in permeability, that helium cannot be used as a surrogate for hydrogen in tight materials like salt, but that salt remains an attractive underground storage alternative for hydrogen.

12. Risk related regulatory documents written for underground natural gas storage are largely generic enough to apply to underground hydrogen storage. However, some hydrogen-specific regulations do not apply to underground storage and there may be some gaps there. The main contributors to risk at a depleted hydrocarbon reservoir wellhead and at an aboveground processing facility are from thermal effects versus overpressure risks, and the aboveground processing facility dominates risk compared to a wellhead scenario.

13. With respect to development and implementation of a hydrogen field scale test, industry stakeholders have suggested: 1) think about doing multiple tests in different types of storage reservoirs; 2) use a gas storage field because the base gas is there and operations are in place; 3) start with perhaps 10% hydrogen and blend up to 100% to observe the behavior of equipment while monitoring surface and subsurface fluids; 4) use a newer facility rather than a legacy mothballed one to avoid results driven by the age of the system; 5) run the test near a community with a robust outreach program to build public confidence; 6) run a long test cycle of at least 2 years; 7) use a lower reservoir pressure (~1200 psi) to save on compression costs and reduce leakage risk; 8) design for representative delivery rates (~2MMscfd minimum) and storage volumes (~2 Bcf); and 9) pay attention to microbial interactions.

14. IEA's hydrogen technology collaboration platform (TCP) has 33 members, 40 tasks and 250 experts collaborating on six subtasks: geochemical and microbial impacts, storage integrity, storage performance and testing, facilities and wells, economic and system integration, and societal embeddedness of UHS. A preliminary report is available on the IEA website and a final report on Task 42 is expected at the end of 2024.

15. Phase I of DOE's $15MM pipeline blending CRADA, The Hyblend Project is completing. The focus has been on materials compatibility with hydrogen and techno-economic and life-cycle analyses. PNNL work discovered that hydrogen exposure actually improves polymer pipe performance. Another output is a Blending Pipeline Analysis Tool for Hydrogen (BlendPATH) that provides case-by-case techno-economic analyses. ANL work has resulted in analyses based on a GREET Model that show that for a constant energy delivery scenario, net life cycle emissions are reduced by less than 2% at a blend ratio of 30%, due to higher emissions from the generation of hydrogen. Phase II of the CRADA with the same labs is underway. $12M in DOE funding is available for the three-year CRADA. DOE is seeking cash co-funding.

16. The USGS is identifying amenable depleted hydrocarbon reservoirs in the Wind River Basin, calculating probabilistic gas capacity estimates in the Michigan Basin, and modeling potential hydrogen chemical reactions during subsurface storage in the Illinois Basin. The USGS is also looking at natural occurrences of subsurface hydrogen around the world.

17. GeoH2, an industry consortium (15 sponsors) seeks to conduct reservoir engineering and economic research to facilitate and advance the development of a hydrogen economy at scale. They have established three research "pillars": geological storage, techno-economic and value chain analysis, and *in situ* generation and novel concepts. One work product of the consortium is a thermodynamic simulator to assess the technical potential of hydrogen storage, injection, withdrawal, and cycling operations in salt caverns. In addition, the consortium is publishing two reports on salt dome considerations in the Gulf Coast. A web-based screening and cost tool called HyFive will be made available to sponsors in June 2024.

18. A GeoH2 case study looked at using electricity produced from an 80 MW wind farm in West Texas to operate a 21 MW electrolyzer to produce hydrogen when electricity prices are low. Adding salt storage to the facility to store hydrogen allows the operator to convert it back to electricity using a simple gas turbine when market conditions are profitable. The analysis concluded that with a capital cost, including cushion gas, of $15.9 million, given the spread in peak and off-peak electricity, the hydrogen value spread can provide a 17% internal rate of return on investment. The breakeven cost of hydrogen storage is $1.21/kg.

19. A techno-economic evaluation of hydrogen geologic porous reservoir storage determined that screening is very important, the initial cushion gas is not a key cost concern, but loss of hydrogen in initial years is a key factor in economic viability. Also, the number of wells drilled and compression costs are the two most important cost factors.

20. A national lab techno-economic analysis of UHS in the Intermountain West showed that storage costs varied from 1.1 $/kg to 2.3 $/kg to 3.2 $/kg in depleted gas reservoirs, salt caverns and saline aquifers, respectively. In terms of capital costs, the largest share of costs for gas reservoirs and saline aquifers was cushion gas at 79 to 88%, while site preparation was 72% of the cost for salt caverns. Levelized cost estimates showed that compression costs were 28% of total levelized costs for depleted gas reservoirs, while only 12 to 10% for salt caverns or saline aquifers. Costs are lower if methane or nitrogen rather than hydrogen is used for cushion gas, even after accounting for purification.

Speaker 1: Evan Frye, Prgm. Mgr. for DOE Natural Gas Decarbonization and Hydrogen Technology, Office of Resource Sustainability, Methane Mitigation Technology Division

Evan began with an overview of the Division and the Program for which he is responsible. He noted that a recent FOA (FOA2400) had four topical areas of interest (AOIs) relevant to the division's mission, and one of these, AOI 16, was specifically focused on fundamental research to enable high-volume, long-term, subsurface hydrogen storage.

There were four project awards under this AOI: GTI Energy's project to determine the potential for subsurface storage ($1.4MM), U. of ND EERC's Williston Basin storage resource study ($1.5MM), U. of Texas at Austin's Permian Basin salt cavern study ($1.483MM), and Virginia Tech's Appalachian Basin depleted gas field storage study ($1.5MM).

Evan then provided a high-level overview of Subsurface Hydrogen Assessment, Storage, and Technology Acceleration (*SHASTA*) program's objectives and goals. The effort is trying to de-risk and scale up hydrogen storage. Storage will be key to enabling a sustainable hydrogen economy. Four national labs are involved: NETL, PNNL, SNL and LLNL. DOE has also formed and agreement with U.S. DOT PHMSA for related research.

The primary objective of the meeting is to figure out *SHASTA* challenges and potential solutions and research gaps that we haven't identified. We are also looking for site owners interested in pilot-scale studies.

Speaker 2: Josh White, LLNL, one of four co-PIs for *SHASTA*

Josh provided a more detailed overview of *SHASTA*. The objectives are to quantify available hydrogen storage resources in widely diverse locations, as well as quantify operational risks and potential losses, and develop enabling technologies and recommended practices, and develop collaborative R&D and field testing.

SHASTA was originally a 3-year project beginning in the end of April 2021, and we are now at the end of that first 3-year period. Currently in the process of extending into a fourth year, with the potential of further extension to address unmet needs up for discussion.

Josh then described the agenda for the meeting. The morning sessions would be presentations by *SHASTA* researchers from the four national labs, while the afternoon presentations would be made by representatives from industry and other institutions focused on hydrogen storage.

Speaker 3: Leon Hibbard from PNNL discussed regional Case Studies for hydrogen storage. DOE has announced seven clean hydrogen hubs across the US. Storage will be an integral element of each of these hubs. Depleted gas reservoirs and solution-mined salt caverns are two options currently being targeted for hydrogen storage (four salt cavern storage sites are planned), but abandoned oil reservoirs and saline aquifers are also being considered. We are working on two case studies, the first in Cook Inlet Alaska. Hydrogen storage there would enable the export of energy from future wind power resources to markets with greater demand. The second in Pennsylvania, where there are many oil and natural gas pools and natural gas storage fields in use.

Using publicly available data (state agencies and USGS) to evaluate potential storage sites, the approach involves 1) storage volume assessment, and 2) physical and chemical suitability assessment (containment and lack of biochemical interactions). In the Cook Inlet, Alaska assessment it was determined that around

286 TWh of hydrogen working gas could be stored in Cook inlet pools. There were found to be 29 hydrocarbon pools and 2 natural gas storage pools that could meet a theoretical demand. 48 pools were determined to be "inactive or non-producing" and thus available. Rock property and geologic analysis of all pools indicated that seven were available, offered adequate storage volumes, and had favorable geologic and rock property characteristics for hydrogen storage. These seven pools are distributed across three fields. Next step is to carry out site characterization to determine development suitability and increase confidence in our ability to utilize each of these pools as potential hydrogen storage sites.

In the Pennsylvania assessment it was determined that about 2100 TWh of hydrogen storage using a volumetric assessment method. The physical and chemical suitability assessment is still ongoing, but so far has indicated that some formations (Oriskany, Elk) exhibit properties that might be relatively favorable for hydrogen storage.

In summary, Leon noted that an adaptable methodology for assessing hydrogen storage opportunities was successfully demonstrated, despite substantial variability in data availability and quality between states.

Speaker 4: Gerad Freeman and Shruti Mishra from PNNL and SNL, respectively, discussed a framework for local and regional-scale technoeconomic analysis of subsurface hydrogen storage. The work has attempted to build on previous DOE work related to the economics of hydrogen storage by focusing specifically on the economics of subsurface storage. This is done by building a system of equations to represent subsurface system configurations needed to meet withdrawal and injection requirements, adding a cost/revenue model that can be used to identify the relevant tecno-economic analysis (TEA) site screening criteria should be. The goal is to package this together as a module that can be added to the existing toolbox DOE has developed for modeling the hydrogen end use, delivery, and production elements of the hydrogen energy value chain. All of this will be used to drive spatially-scalable case studies that reflect all of the costs of hydrogen energy.

The work utilized H2@Scale's 2050 hydrogen market potential estimates as a starting point. A logistic-shaped adoption model was used to model the behavior of innovators and imitators as new hydrogen users in industrial, chemical, and power sectors. Data-driven methods were used to model existing users. Two adoption scenarios were defined to bound the analysis. This presentation focuses on the "full market realization" scenario and how that looks for hydrogen demand over time for various market sectors between 2024 and 2050. Future work will focus on establishing a lower boundary for demand over time.

The work then modeled the demand for each sector over time, at the county level, across the northern Appalachian study region, including Ohio, New York, Virginia, West Virginia, New Jersey, Delaware, and Rhoad Island. To understand how much hydrogen storage would be needed to handle that demand level, the team looked at how underground gas storage is used to buffer natural gas demand and how much total annual gas demand cycles through storage. The team is currently working to answer questions about the impacts of the timing of demand changes, blending of hydrogen in natural gas, switching to hydrogen as an energy source for vehicles, and the timing of power grid demand peaks on demand patterns and gas cycling behavior. The team utilized their findings to look at the storage demand across the state of Pennsylvania, by county, to begin to understand where hydrogen storage should be located.

The next step was to screen those possible higher priority locations by the cost of storage, based on the relative costs of storing hydrogen in the subsurface options available. We know from past work that hydrogen subsurface storage costs, both capital and operating, vary widely. This work looked to identify the major cost drivers and the potential cost reductions possible for each attribute, how these cost drivers change across different types of storage, and what would be the significance of these cost factors across a state or region, in determining the location of hydrogen storage facilities.

The team envisioned the CAPEX cost categories for a subsurface storage site (e.g., site characterization, cushion gas, compression, well construction, monitoring, surface equipment, salt cavern creation if needed), as well as the OPEX cost categories (e.g., compression, well operating, transportation) and built relevant equations for each. The team looked first at a 20MMcf/d facility, both salt cavern and depleted hydrocarbon reservoir options. They developed levelized cost drivers for different UHS types and storage capacities. They then applied this framework to calculate the cost of hydrogen storage at a number of depleted reservoir sites in Pennsylvania, using public data. The team learned that the levelized costs vary significantly based on storage site characteristics. Smaller sized sites have higher levelized costs and shallower well sites have lower costs. Further, the levelized costs can be reduced by 45% if cushion gas and electricity costs are lowered by 25% and 50%, respectively.

The team also looked at how cost factors changed by site across PA and by state across the region. State-wise variability in costs is a function of site preparation, permitting, well drilling, electricity, wages, taxes, etc. In looking at various depleted hydrocarbon reservoir sites, the team noted that cushion gas costs varied widely, from 42% to 74% of total costs. Across Northern Appalachia the levelized cost of salt cavern storage was lower than aquifer storage, and the levelized costs dropped with increased total capacity of the site. All other things being equal, the levelized costs were lowest in West Virginia, followed by Ohio, and Pennsylvania.

Future work could include integrating the tecno-economic analysis with costs of production and delivery to evaluate where cost reduction efforts should focus to reach a low cost (<$1 per kg) delivered target, developing data-driven estimates of storage adoption for a single operator or site, and conducting inter-regional comparisons and a national-scale analysis.

Speaker 5: Julia Camargo with PNNL discussed reservoir simulations and code comparisons. She began talking about the need to upgrade commercial simulator equations-of-state to account for hydrogen mixtures as a reservoir fluid. Using a compositional reservoir simulator, where the storage reservoir being modeled is an existing natural gas storage field, the team wanted to address three key questions: what is the impact of rock and fluid properties on storage efficiency and energy availability; how can hydrogen/natural gas/brine flow dynamics be managed; and what mechanisms could lead to resource loss? To do this, they learned that while most of the equations in the selected commercial compositional simulator did a pretty good job of handling hydrogen mixtures, however, that was not the case for viscosity. So, they successfully modified the Lohrenz-Bray Clark model to address this shortcoming. The new model is simple to implement, fast, and the only free parameters are the critical component properties.

The team then used the updated simulator to model a synthetic hydrogen storage reservoir with realistic rock properties and an initial saturation of methane. Hydrogen was injected in various design configurations and gas-water contact dynamics were ignored for the moment (modeling a single-phase, two component system). They modeled six-month cycles of injection of 15% by mass hydrogen in natural gas mixtures. The simulations showed that injecting into perforation near the bottom of the reservoir leads to greater mixing of the in-place methane with the hydrogen/methane injected mixture, due to the difference in density between the injected and in-place fluids. Creating a stable hydrogen cap requires attention to the structure of the reservoir (good trapping structure and low vertical permeability) and the placement of perforations in the injection/production well near the top of the storage interval.

Finally, she talked about a code comparison study among different reservoir simulators. The reasons for doing such a study are to illuminate discrepancies among simulators, identify limitations in the current cods, and provide a documented record of benchmark problems for hydrogen storage simulation. The three codes compared were GEOS (LLNL), STOMP EOR (PNNL) and TOUGH (LBNL). These codes were compared using three types of problems: PVT simulations, a core-scale one-dimensional flow problem, and the three-dimensional reservoir simulation of a hypothetical storage system. For PVT and viscosity tests, all three codes were compared to experimental results and the GERG2008 model. All codes agreed very well with the data. For the one-dimensional flow problem (hydrogen invading methane), the team also saw good agreement. The team is currently comparing codes for hydrogen invading water. The team is also currently investigating the three-dimensional simulation of pure hydrogen invading a methane saturated reservoir over multiple injectional and withdrawal periods, comparing STOMP and TOUGH codes.

Speaker 6: Ryan Haagenson, also with PNNL discussed core flooding experiments and simulations. The motivation for this work is to gain a better understanding of how hydrogen, cushion gas methane and formation brine interact in porous media and how we can accurately simulate their flow behavior. The team performed core flooding experiments with hydrogen, methane and brine, studied their flow behavior in sandstone and constrained critical parameters for physics-based simulations. Tests were done flowing through Berea (42 mD, 18% porosity) and Bentheimer (945 mD, 24% porosity) cores. The experiments displaced brine saturated cores with methane, and then displaced the methane with hydrogen. Higher methane injection rates result in higher final saturation of methane in both sandstones. When injecting hydrogen, higher injection rates speed up the time until hydrogen breakthrough, and higher permeability sandstone see quicker breakthrough of hydrogen, as would be expected. The team also looked at the effect of gravity on the displacement of brine with both methane and hydrogen and how it might influence how fluids are moving through the rock. The results suggest that while the influence of gravity on methane displacement of brine is subtle, in the case of hydrogen displacing brine we see an earlier hydrogen breakthrough in the horizontal direction and a less rapid increase in gas concentration. This evidence of gravity override is due to the density contrast, as the gas rises the liquid sinks.

The team also performed one dimensional and three-dimensional core flood simulations using GEOS, an open-source simulator developed at LLNL. The results confirmed the effects of gravity override due to the density difference of hydrogen. The experimental results were not matched entirely however, an indication that other effects such a sub-core heterogeneity may be impacting the speed with which hydrogen concentrations in the effluent rise.

Speaker 7: Djuna Gulliver with NETL discussed microbial characterization in hydrogen storage. This project is part of the risk quantification area of research. The objective is to understand how microorganisms will change and effect the reservoir in hydrogen storage. This will be done through geochemical analysis, DNA analysis, sampling of subsurface material at storage target sites, and simulation experiments and optical sensor. Hydrogen is very active microbiologically speaking and hydrogen storage reservoirs can be expected to have native microbial communities. For example, methanogenesis could turn hydrogen into methane, resulting in a loss of hydrogen, or hydrogen sulfide could be produced, as well as acids that can lead to corrosion impacts. Gaz de France published data showing that 50% of their stored hydrogen was consumed and converted into methane, along with hydrogen sulfide contamination, due to microbial action.

The team collected fluid samples from separator at two methane storage sites. Ionic and organic concentrations were determined form both sets of samples. Chloride and total dissolved solids (TDS) measurements varied between the sites. Baseline taxonomy of microorganisms at each site were done and they proved to be quite different in terms of the microorganisms represented and the level of diversity. Site 1 included a lot of iron mobilizing organisms while Site 2 included sulfur reducing and acetate producing organisms.

The team used Site 2 sample material to create a large batch laboratory scale pressure cell version of the methane storage reservoir conditions and a similar hydrogen storage scenario. Over one-day and three-day trials, it was noted that the hydrogen content decreased due to conversion to methane.

In summary, sites can vary in geochemistry and microbiology despite being relatively close spatially. One can expect a relatively high abundance of organisms with the potential to consume hydrogen through various chemical reaction processes. Initial tests show that kinetic rate will be most important during the 1-to-3-day timeframe when injecting hydrogen into a system. Small batch experiments largely confirmed the findings of the large batch experiments.

Speaker 8: Angela Goodman with NETL discussed hydrogen wettability, permeability and diffusion in the hydrogen storage reservoir context. The primary question is: could hydrogen become the wetting fluid under geologic storage conditions, and leading to losses. This work performed hydrogen-brine contact angle experiments on Nixon shale, Berea sandstone and Class G cement samples and found no change across a range of temperatures, pressures, salinities, and bubble size. Reservoir rocks will remain water-wet at geologic hydrogen storage conditions.

The team also looked at hydrogen movement through shale using a pulse decay system (used for tight samples). The apparatus was used to measure permeability in about ten different shale samples from the Nixon, Eagle Ford, Marcellus, Wolfcamp, and Red Willow shale formations. Hydrogen permeability ranged from 0.000318 mD (Wolfcamp) to 0.002427 mD (Eagle Ford). The same measurements using methane rather than hydrogen did not differ significantly. The team is working to measure diffusion directly in the lab and then to relate these measurements to a rate of diffusion through a caprock. The literature shows diffusion coefficients for hydrogen on the order of 1 x 10 -10 m^2/sec to 6 x 10 -8 m^2/sec.

Speaker 9: Gaby Davilla and Guangping Xu with LLNL and SNL, discussed geochemical impacts of subsurface hydrogen storage on reservoir and caprock characteristics. Introducing hydrogen into a reservoir rock system can cause chemical disequilibria leading to hydrogen loss, production of other gases (like H_2S), and mineral dissolution/precipitation (which can in turn lead to rock property changes that can impact hydrogen injectivity and migration).

The team conducted 12 experiments over 25 (+/- 5) days using rock powder and core samples and using a 10% hydrogen in nitrogen mixture. Berea, Bentheimer, and Eagleford shale samples were used. The experiments were carried out using low salinity water at 1000 psi and 80 degrees C. The results showed slight pH increase and slight hydrogen loss in all cases. Berea sandstone was the least reactive while Eagle Ford Shale was the most reactive (a result of its higher volume of non-silicate minerals). Trace metal levels increased over time. Iron bearing phases showed the greatest reactivity. The team is still refining redox estimates in models for the various rock types. Bulk porosity remained unchanged in the Berea samples but slight fracturing was noted in the Eagle Ford samples.

Guangping began with a discussion of hydrogen/brine interactions with minerals and shale. He introduced a dual high pressure reactor setup. The team first tested hydrogen and pyrite, a common constituent in shales. There was no significant reaction with pyrite due to the presence of hydrogen. The second test was with dolomite. The presence of hydrogen at pressure does not seem to affect the solubility of dolomite. The third test was with sulfate mineral (gypsum). Mixing gypsum and water leads to phase transitions between gypsum, bassanite and anhydrite, with accompanying volume changes that can cause mechanical property changes. However, the addition of hydrogen does not appear to impact sulfate mineral reactions or solubility. The next test involved the exposure of Bakken Shale powder to hydrogen/brine mixture at 2000 psi and 55 degrees C for one week. Hydrogen does not seem to enhance the solubility of shale and there were no mineralogy changes. The team also measured the adsorption of hydrogen by clay at low pressure. The tests confirmed literature data that shows significant amounts of hydrogen can be adsorbed and retained by clay minerals like k-montmorillonite. The adsorption rate is very slow despite the molecular size of hydrogen. The team also tested adsorption in Marcellus shale. In summary, hydrogen does not seem to enhance the solubility of minerals in brine. Hydrogen adsorption can be significant; nearly 23% can be irreversible. However, hydrogen adsorption capacity decreases after the initial adsorption. Hydrogen adsorption rate in clay is slow but several more times the volume than methane can be adsorbed, and methane can be desorbed during the process. After hydrogen adsorption, the pore microstructure changes; pore volume shrinks and pore size decreases.

Speaker 10: Barbara Kutchko and Guangping Xu with NETL and SNL, discussed well integrity. Barbara began by outlining the characteristics of hydrogen and wellbore cement. In general, hydrogen has a high effusion rate, but because cement is a complex porous material, hydrogen movement through cement can be variable. The cement pore network is controlled by water/cement ratio, cement type, additives, particle size, curing time, curing temperature and pressure. Previous research has found that hydrogen permeability in cement decreases with curing time and increases with water/cement ratio. The team measured gas permeability (hydrogen, methane and nitrogen). Nitrogen was used to see if it could be used as a proxy for hydrogen. The cements used were Class H and Class G, with and without fly ash additives, at various water cement ratios. Measured permeability (using a pulse decay permeameter) for hydrogen, nitrogen and methane tracked closely across the cement types. Batch reaction experiments did not reveal any indications of discernable changes in chemistry or microstructure from hydrogen exposure.

Guangping discussed measurement of cement sample pore volume and pore size distribution. Pozzolan cement (fly ash additive) appears to have higher surface area and higher pore volume and adsorbs less hydrogen than class H cement. Hydrogen adsorption is very low however, less than 100 mg per kg at 0 degrees C and atmospheric pressure. Cement exposed to mixtures of hydrogen and brine showed some dissolution of $Ca(OH)_2$ components, but this did not appear to be related to hydrogen content. The inference overall is that the presence of hydrogen will have little to no influence on wellbore cement integrity in a subsurface hydrogen storage reservoir.

Speaker 11: Christopher San Marchi with SNL discussed hydrogen embrittlement of metals. The presentation was largely a primer on the topic rather than a discussion of specific *SHASTA*-related SNL experimental work. There are three components in the hydrogen embrittlement problem: environment, stress/mechanics, and materials. Hydrogen embrittlement occurs in materials under the influence of stress in hydrogen environments. There are many different combinations of factors within these three areas that affect material behavior. There are a number of different materials used in engineered systems where hydrogen could cause embrittlement. Many of these materials have been extensively tested and their performance under exposure to hydrogen is well understood. Christopher introduced fracture mechanics-based testing to assess the structural integrity of a material (fatigue crack growth and fracture toughness measurements). These are factors that the team measured as well. Christopher emphasized that testing results can be influenced by subtle difference (e.g., the purity of the hydrogen used in the lab) and as a result there is a lot of misinformation in the literature and thus a lack of consensus on some aspects of the hydrogen embrittlement question. Christopher introduced the concept of R ratio and the relationship between pressure and the amount of hydrogen that is dissolved into the metal. Next, Christopher discussed a variety of SNL test data for a number of different materials (carbon steel, low-alloy steels, high-alloy steels).

Speaker 12: Ruishu Wright with NETL discussed real-time sensor technologies for hydrogen surface storage. The objective of the work was to advance the development of optical fiber sensors that would enable real-time monitoring of hydrogen, methane and chemical parameters under subsurface hydrogen storage conditions. These data are needed to monitor microbiological consumption of hydrogen, pH changes, and well integrity risks. Real-time sensing avoids the need for periodic sampling. Optical fiber sensors were identified as the best candidate given their safety, stability, flexibility, size, functionality, and distributed sensing capability. NETL has developed its own portfolio of distributed optical fiber interrogator systems for monitoring pipeline and wellbore temperature, strain, vibration, and chemical changes, as part of its natural gas leak detection program. The team determined that there is a lack of commercial hydrogen sensors compatible with mixed methane/CO_2/hydrogen/water environments at hydrogen storage conditions, but that NETL's sensors are compatible. Ruishu then described the NETL fiber construction and its performance characteristics.

The team simulated high pressure/high temperature (HPHT) wellbore conditions with microbial samples in a reactor. The hydrogen sensing capability of the sensor was not affected by methane or biotic activity across a range of hydrogen concentrations. The sensor successfully detects changes in hydrogen concentration resulting from biotic activity. The system was also shown to operate successfully for pH sensing. Plans are to optimize the sensor, ruggedize it, completely calibrate it at HTHP conditions and then deploy it in actual wellbore locations to validate it under controlled conditions.

Speaker 13: Mathew Ingraham with SNL discussed salt mechanics. He began with a description of the differences between bedded and domal salt deposits. He noted the four domal hydrogen storage locations, 1 in UK and 3 in US. He then listed the pros and cons of bedded versus domal salt for hydrogen storage.

The research team used core samples from salt formations and tested them for hydrogen and helium permeation at different pressure differentials. They found that helium passed through dirty salt much more quickly. Hydrogen through-put came to a steady state in about half the time as helium in clean salt. The implications are that the presence of interbeds can cause significant increase in permeability, that the relative permeability of helium versus hydrogen is different (i.e., helium cannot be used as a surrogate for hydrogen in tight materials like salt).

Conclusions are that salt remains an attractive underground storage alternative for hydrogen. Cavern storage is ideal, but locations are limited to Gulf Coast in the US. Bedded salt storage presents challenges but is possible. Types/quantity of interbeds may eliminate some locations depending on the acceptable amount of hydrogen loss.

Speaker 14: Josh White with LLNL discussed recommended practices for developing and operating subsurface hydrogen storage facilities. LLNL approached this by asking the question: What is the delta compared to existing best practices for underground natural gas or carbon dioxide storage? He then described the recommended, three-stage, project-development workflow for UHS facilities. It is similar to the API Recommended Practice 1171 2nd Edition, November 2022 for natural gas storage in depleted hydrocarbon reservoirs and aquifers.

Speaker 15: Melissa Louie with SNL discussed risk assessment frameworks for underground hydrogen storage facility leaks. The team did a review of existing regulations applicable to UHS. They learned that documents written for underground natural gas storage were largely generic enough to apply to underground hydrogen storage. They also learned that some hydrogen-specific regulations do not apply to underground storage and that there may be some gaps there.

The team also did a sample quantitative risk assessment calculation to show that such a risk assessment could be done on a particular wellhead or site. Using generic system configurations and leak/pathways/sources, the team developed contour plots to show the main contributors to individual risk at a depleted hydrocarbon reservoir wellhead and at an aboveground processing facility. They learned that thermal effects dominate overall risks compared to overpressure risks, and that the aboveground processing facility dominates risk compared to the wellhead scenario.

The team learned that certain components/pathways have high leak frequencies, certain components decrease risk (e.g., Downhole safety valve), higher Mach flame speeds cause higher overpressure risk, and ambient temperature affects heat flux risk.

Speaker 16: Franek Hasiuk with SNL discussed a hydrogen field scale test plan. There is not yet a site for this a field scale test, but while site specific work cannot be done, we can think more broadly about planning for a representative site, specifically; What are the questions that we need to answer and who are the people who need that information? Fundamentally, a first demonstration site could be in a sandstone depleted gas field of similar scale to a current gas storage operation.

The primary objective of a test site is to collect data that is useful for industry seeking to design a hydrogen storage site, and for regulators seeking to permit such sites. Franek noted that there are actually three different types of hydrogen reservoirs: hydrogen storage (hydrogen in and hydrogen out), natural hydrogen accumulations (more work is being done on exploring for and characterizing these), and stimulated hydrogen reservoirs (where injected water is used to chemically produce hydrogen in the subsurface; ARPA-E grants recently).

Franek noted that there is a long history of natural gas storage field development and operation, with most fields being brought online in the 1940s-1970s, but that the relative increase in natural gas prices post-1980 has limited additions to the gas storage portfolio of fields, due primarily to the cost of base gas. Most gas storage reservoirs are in depleted oil and gas reservoirs that are sandstone formations, and most are Late Paleozoic rocks.

We may need to think about doing multiple tests in different types of storage reservoirs that are representative for the region of the country where the site is located. A number of suggestions as to what the test would need to include were made by stakeholders (industry and permitting agencies). These included: use a gas storage field because the base gas is there and operations are in place; start with perhaps 10% hydrogen and blending up to 100% to observe the behavior of equipment and monitoring surface and subsurface fluids; use a newer facility rather than a legacy mothballed one so that a clear picture of the impact of hydrogen on surface and subsurface materials is not driven by the age of the system; run the test near a community with a robust outreach program to show the safety and benefits and build confidence in the public; and run a long test cycle of at least two years.

Other suggestions included: using a lower reservoir pressure (~1200 psi) to save on compression costs and reduce risks of leakage; designing for delivery rates (~2MMscf/d minimum) and storage volumes (~2 Bcf) representative of current natural gas storage operations; paying attention to the potential for hydrogen to react with microbial communities.

Franek also listed the eight major research questions that need to be addressed in any hydrogen field test project. Some of these questions are being investigated in the lab now but need to be tested in the field. The notion of creating a dedicated field laboratory for a variety of research efforts was raised.

Speaker 17: Serge van Gessel discussed hydrogen TCP Task 42. This presentation was essentially a summary of a recent report from the group on the status of UHS around the world. IEA's hydrogen technology collaboration platform (TCP) has 33 members, 40 tasks and 250 experts collaborating. Task 42 has six subtasks: geochemical and microbial impacts, storage integrity, storage performance and testing, facilities and wells, economic and system integration, and societal embeddedness of UHS. A report is available on the IEA website.

One idea noted in the report is the need to build confidence in UHS management across four technical domains: geological, engineering, the energy system, and society embeddedness. Serge displayed a table from the report showing a significant number of pilot and commercial projects, many in Europe, across the entire range of hydrogen storage options, showing where these projects are along the concept to completed spectrum. At least eight projects in porous reservoirs (non-cavern) and eleven cavern projects are in the construction-injecting-completed in range. He also displayed a framework for how to align the TRL levels of UHS with development stages. Serge also commented on the challenge of integrating all of these cross-cutting issues into a single model for evaluating the suitability of UHS sites and projects.

Next, Serge commented on the degree to which confidence is being built in legislation, communication, participation and markets, that is; What is the confidence of the public and the markets in UHS? He suggests a TRL type framework for societal embeddedness level and risk confidence level. A final report on Task 42 is expected at the end of 2024.

Speaker 18: Todd Deutsch with NREL discussed the pipeline blending CRADA, The Hyblend Project. This project was conceived in the understanding that there is an extensive natural gas pipeline system in the US that could offer a low-cost pathway for distributing green hydrogen if it is blended into the natural gas stream in a safe manner. Buring a hydrogen/methane blend offers an incremental approach towards cost-efficient pure hydrogen transport and end use, and associated carbon emissions reductions. It is projected that there will be a much greater supply of hydrogen and demand in the near future, and this approach would provide a practical sink. Phase I of the $15MM CRADA is just completing. It includes 4our national labs and 31 partners from industry and academia. The focus has been on materials compatibility with hydrogen and techno-economic and life-cycle analyses. SNL is providing probabilistic software tools for structural integrity assessment of hydrogen pipelines. PNNL is looking at how blended gases affect high density plastic pipeline materials. ANL is looking at a life-cycle analysis of energy delivery that relates hydrogen blending percentage to carbon emissions reduction. NREL is looking at software development that can provide economic analysis of transmission pipeline using blended mixtures. Todd provided a brief description of how each of these efforts are structured, including collaborative partnerships.

Todd then highlighted one of the findings: the PNNL work discovered that hydrogen exposure actually improves polymer pipe performance. The NREL work has resulted in a comprehensive technical literature review that has been published. Another output is a Blending Pipeline Analysis Tool for Hydrogen (BlendPATH) that provides case-by-case techno-economic analyses. The ANL work has resulted in analyses based on a GEET Model that show that for a constant energy delivery scenario, net life cycle emissions are reduced by less than 2% at a blend ratio of 30%, due to higher emissions from the generation of hydrogen.

Todd then summarized the key activities, findings and outputs from Phase I. Additional work needed included: the development of risk assessments related to safety, development of codes and standards; development of technologies for remediation of vintage pipelines using coating, pull through composite liners, and repair technologies; and the evaluation of system components that will be exposed to hydrogen.

Phase II of the CRADA with the same labs is underway. $12M in DOE funding is available for the three-year CRADA. DOE is seeking cash co-funding.

Speaker 19: Carolyn DesCoteaux with the Pipeline Research Council International (PRCI) discussed the Emerging Fuels Institute. PRCI is an association of about 66 pipeline operators. About 21 of these members have formed the Emerging Fuels Institute. They are trying to determine the feasibility of blending hydrogen into existing gas pipelines. How do we repurpose an existing pipeline? The objectives of the EFI are to develop guidance documents, build relationships, develop industry standards, support the development of informed regulations, and act as a clearinghouse for information.

The EFI put together a gap analysis that discovered about 60 major gaps in the state of the art related to hydrogen in pipelines. Fifteen of these gaps are focused on pipeline integrity. EFI has implemented 38 projects to help close these gaps. Carolyn also mapped the PRCI research focus areas to a similar list of gaps developed by PHMSA.

Next steps are to complete the current research through 2026, continue to engage industry through ASME and API standards, address any remaining identified gaps, prepare a guidance document, carry out full-scale testing (on full-sized pipe elements rather than samples), participate with DOE in HyBlend 2 CRADA, and address CO_2 transport and sequestration.

Speaker 20: Peter Warwick with the USGS provided an overview of research in energy storage in general and hydrogen storage specifically at USGS. Research on assessing gas storage resources include work on a new assessment methodology for natural gas storage and potentially hydrogen storage volumes in depleted gas reservoirs. Examples include identifying amenable depleted hydrocarbon reservoirs in the Wind River Basin, calculating probabilistic gas capacity estimates in the Michigan Basin, and modeling potential hydrogen chemical reactions during subsurface storage in the Illinois Basin.

In the Wind River Basin example, the USGS is using commercial well databases to identify clusters of idle wells that are unlikely to come back online (five or more years offline) and combine them with geologic mapping to estimate field areas where depletion may support natural gas storage activity.

In the case of Michigan, there are quite a few reservoirs, based on state databases, where storage may be possible. The USGS is looking at cumulative gas production, reservoir volume estimates and a pressure-drop method to estimate what the storage potential of these reservoirs might be. These calculations are compared to working gas capacities from operating facilities in Michigan. This method will be applied basin-by-basin pending verification of amenable depleted reservoirs. A report on this work is in production.

The USGS is also modeling underground hydrogen storage in porous reservoirs in the Illinois Basin (Aux Vases Sandstone) looking specifically at understanding SO_4 redox reactions that begin after hydrogen injection and resulting biomass growth.

The USGS is also looking at natural occurrences of subsurface hydrogen around the world. Observations of subsurface hydrogen at concentrations of >10% are widespread but do not occur in the basins we are familiar with for hydrocarbons. Primarily, hydrogen is found in serpentinites, along Mid-Ocean ridges, in non-sedimentary hard rocks and in volcanic/magmatic hydrothermal locations. The high diffusivity and reactivity of hydrogen probably means that accumulations cannot form, but there are exceptions. However, depleted underground natural hydrogen reservoirs would likely make ideal candidates for underground storage.

Speaker 21: Ning Lin with the Texas Bureau of Economic Geology discussed screening and valuation frameworks for viable hydrogen storage with GeoH_2. GeoH_2 is an industry consortium (15 sponsors) seeking to conduct reservoir engineering and economic research to facilitate and advance the development of a hydrogen economy at scale. They have established three research "pillars": geological storage, techno-economic and value chain analysis, and *in situ* generation and novel concepts. In the first of these, GeoH_2 is seeking to understand hydrogen subsurface behavior and develop technology and work flows for best practices. In the second they are seeking to assess the hydrogen value chain of supply-transport-storage-use for various markets and also develop a calibrated storage screening tool. In the third they seek to evaluate the potential for *in situ* generated and natural hydrogen and conduct research on novel, high reward opportunities.

Ning then described one work product of the consortium, a Salt Storage and Cycling Application. This is a thermodynamic simulator to assess technical potential of hydrogen storage, injection, withdrawal, and cycling operations in salt caverns. The tool can also be used for bedded salt storage. In addition, the consortium is publishing two reports on salt dome considerations in the Gulf Coast.

As well, GeoH_2 has access to more than 4000 feet of continuous core within the evaporitic sequence of the Permian Basin (Castile and Salado formations). This and other material available in BEG's core library can help in understanding the variations in salt properties.

Ning then presented a case study looking at using electricity produced from an 80 MW wind farm in West Texas to operate a 21 MW electrolyzer to produce hydrogen when electricity prices are low. Adding salt storage to the facility to store hydrogen allows the operator to convert it back to electricity using a simple gas turbine when market conditions are profitable. The analysis concluded that with a capital cost, including cushion gas, of $15.M, given the spread in peak and off-peak electricity, the hydrogen value spread can provide a 17% internal rate of return on investment. The breakeven cost of hydrogen storage is $1.21/kg.

The consortium also did a techno-economic evaluation of hydrogen geologic porous reservoir storage. They determined that screening is very important, the initial cushion gas is not a key cost concern, while the higher loss of hydrogen in initial years is a key factor. Also, the number of wells drilled and compression costs are the two most expensive capital cost factors.

Ongoing plans are to evaluate viable commercial geologic storage opportunities in the early investment phase, and to develop a contracting and operation strategy based on route-to-market analysis. A web-based screening and cost tool called HyFive will be made available to sponsors in June 2024.

Speaker 22: Shadi Salahshoor with GTI discussed SUSTAIN H_2, a collaborative effort to accelerate the deployment of safe and cost-effective long-term underground hydrogen storage through a combination of scientific expertise, market insights, field experience and industry collaboration. GTI is engaging existing partners and prospective participants during 2024 and plans on implementing a field pilot in the 2025+ time frame. Their objective is not to be duplicative but to leverage other researchers' work and facilitate industry collaboration. The DISSPATCH H_2 project in the south-central region is looking at microbial impacts, injection experiments, geologic and reservoir modeling and market and techno-economic analysis. A second project in the Midwest region is focused on aquifer storage in the Illinois Basin. Sandstone core samples have been used for laboratory experiments to provide data for reservoir modeling under a number of scenarios. Later this year work will begin on an assessment of the infrastructure needs, required operational framework, and evaluation approaches for a commercial-scale development.

Speaker 23: Mohamed Mehana with LANL provided an overview of LANLs underground hydrogen storage projects. Currently there are six hydrogen storage projects at LANL These are focused on: resource assessment/techno-economic analysis of UHS in the intermountain west; subsurface transport/reactivity and caprock integrity; infrastructure risk assessment; risk reduction through seismic monitoring; loss assessment; and seal integrity evaluation of salt caverns.

The first of these showed that in the intermountain west storage costs varied from 1.1 $/kg to 2.3 $/kg to 3.2 $/kg in depleted gas reservoirs, salt caverns and saline aquifers, respectively. In terms of capital costs, the largest share of costs for gas reservoirs and saline aquifers was cushion gas at 79 to 88%, while site preparation was 72% of the cost for salt caverns. Levelized cost estimates showed that compression costs were 28% of total levelized costs for depleted gas reservoirs, while only 12 to 10% for salt caverns or saline aquifers. Costs are lower if methane or nitrogen rather than hydrogen is used for cushion gas, even after accounting for purification.

The second project is a large one with three objectives: (1) Assess the rate, extent and mechanism of hydrogen-mineral interactions and their influence on hydrogen recoverability, contamination, and transport during storage, (2) evaluate hydrogen transport properties within storage reservoir rocks and caprocks, and (3) determine the feasibility of hydrogen geologic storage in porous reservoir rocks and identify site characteristics that promote efficient storage.

Mohamed briefly summarized the progress on the remaining projects before highlighting the difference between the number of papers published on CO_2 storage versus hydrogen storage; hydrogen is lagging CO_2 by 20 years.

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