REPORT
221

HYDROGEN STORAGE POTENTIAL OF DEPLETED OIL AND GAS FIELDS IN WESTERN AUSTRALIA

LITERATURE REVIEW AND SCOPING STUDY

RISC

Government of Western Australia
Department of Mines, Industry Regulation and Safety

Geological Survey of Western Australia

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PERTH 2021

Geological Survey of Western Australia

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This Report presents the results of a study by RISC under contract with the Department of Mines, Industry Regulation and Safety (DMIRS). Although DMIRS has provided data for this study, the scientific content of this Report, and the drafting of figures have been the responsibility of RISC. No editing has been undertaken by DMIRS. The Report represents and expresses the research, information, findings, outcomes and recommendations solely of RISC and does not in any way represent the views, decisions, recommendations or policy of DMIRS. DMIRS does not accept any responsibility for the study in any matter whatsoever and does not endorse any views, information, product, process or outcome arising out of or in relation to the study.

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Cover photograph: Mt Horner 5A in production in 1991 next to the hill after which it is named. The Mt Horner oilfield was shut-in during 2011 (photo by AJ Mory) decisions with confidence

Hydrogen Storage Potential of Depleted Oil and Gas Fields in Western Australia

Literature Review and Scoping Study

Department of Mines, Industry Regulation and Safety
Ref: DMIRS20408

August 2021

1. Executive summary

The Government of Western Australia has developed a renewable hydrogen strategy with the vision that Western Australia will become a significant producer, exporter and user of renewable hydrogen. Western Australia has outstanding potential for renewable energy, with an abundance of sun, wind and space. The Western Australian Renewable Hydrogen Roadmap (November 2020) includes the evaluation of utilising depleted oil and gas fields for hydrogen storage. A key aspect is the ability to store the hydrogen on a transitory basis and to be able to recover the hydrogen in high concentrations.

The Western Australian Department of Mines, Industry Regulation and Safety ('DMIRS') commissioned RISC to conduct a literature review of hydrogen storage and scoping study of storage potential of depleted oil and gas fields in Western Australia ('WA'), along with a high-level literature review of other examples of underground hydrogen storage such as aquifers, salt caverns, underground mine sites and tunnels. RISC notes that there are alternative options for storing hydrogen on a transitory basis, such as surface and chemical methods, which are not included in the scope of this review.

The global subsurface hydrogen storage industry is at an embryonic stage. The subsurface storage of hydrogen is currently limited to a handful of caverns manufactured by dissolving the salt by pumping water. There are currently no depleted oil or gas fields used to store pure hydrogen, although there are examples of storage of 'town gas' or 'synthetic gas' with hydrogen concentration in the range of 20% to 60%. Similarly, there are no examples of aquifers, underground mine sites or tunnels currently used for hydrogen storage.

In spite of the infancy of the industry, there are many published articles related to hydrogen as it is seen that it will become a major enabler for companies and countries to reach their net zero greenhouse gas ('GHG') emission aspirations and targets. The literature covers how the hydrogen industry is developing, progress and aspirations of various countries, what subsurface sites are being considered, technical challenges and risks of the various options and alternates to subsurface storage (surface and chemical). There is very limited information directly related to the potential of depleted oil and gas fields in WA.

Salt caverns are the most robust means of storing hydrogen and have been proven to work. Salt acts as an excellent seal, the caverns size can be customised to operational requirements, they have a relatively high gas recovery and injection/production cycle time in the order of days/weeks. The draw-back is the limited locations of suitable salt, the need to access to large amounts of water in their manufacture and the need to dispose of the generated brine.

Storing hydrogen in porous media (depleted gas and oil fields or aquifers) presents several challenges and remains largely unproven. The physical behaviors and properties of hydrogen are different to natural gas. Hydrogen is more chemically reactive which may affect the reservoir lithology, flow behaviour and seal capacity. Hydrogen is also an energy source for subsurface microbial processes which can turn the hydrogen into hydrogen sulphide or react with CO_2 to form methane. In addition, the size of the site is fixed and cannot be customised to operational requirements and injection/production cycle times are typically the order of months rather than days.

Figure 1-1 shows some of many renewable energy sites being considered in WA, many of which have the intent to produce hydrogen. The largest ones are the Western Green Energy Hub ('WGEH') and the Asian Renewable Hub ('AREH') which are world scale. The WGEH is located in the south-east of Western Australia with the aspiration to generate up to 50 GW of solar and wind power over 15,000 km^2.

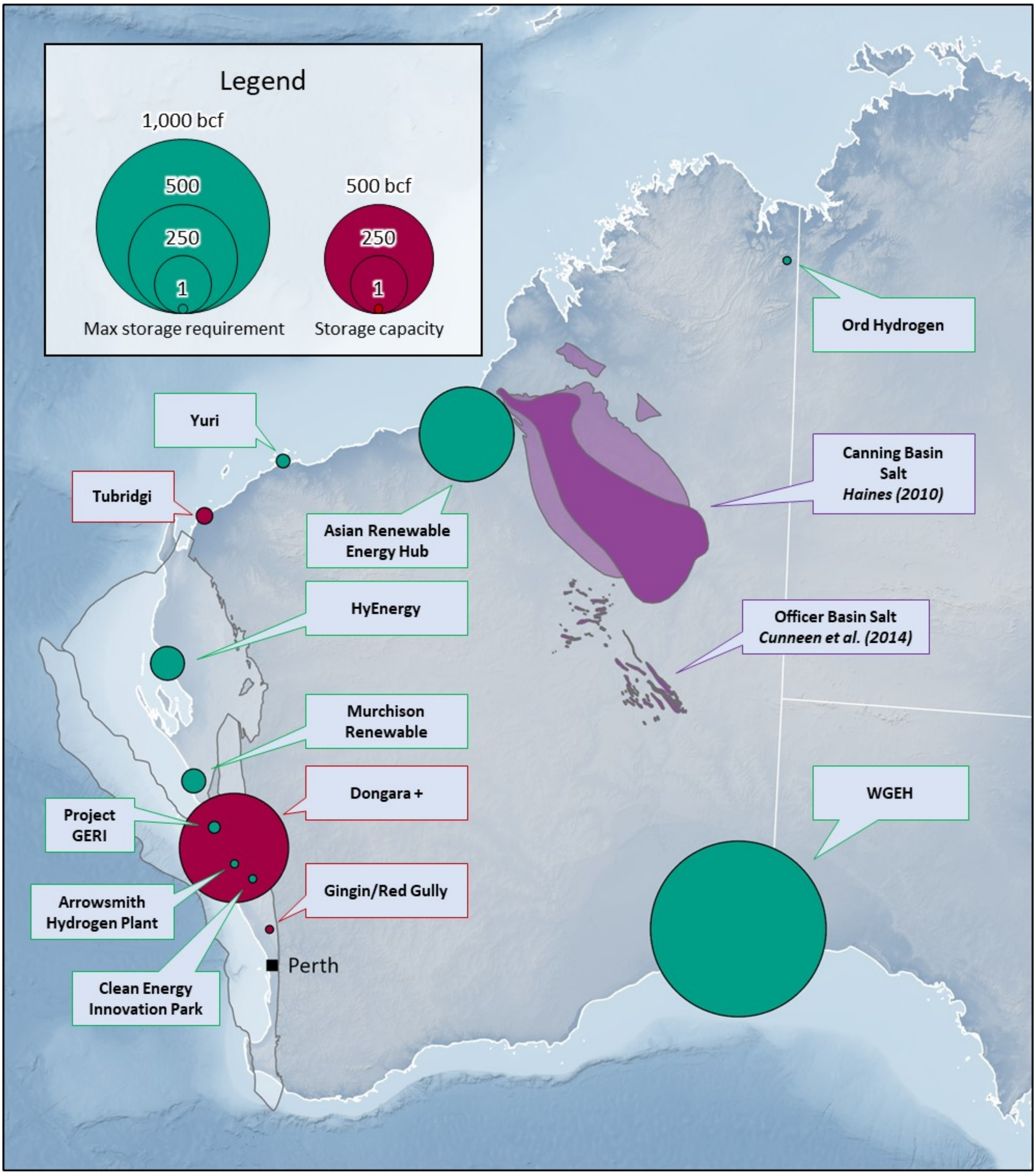

Figure 1-1: Location of WA renewable energy projects and potential hydrogen storage sites

The AREH project is proposed to be located in the East Pilbara region of WA and aspires to generate 26 GW of wind and solar generation, with up to 23 GW of generation for the production of hydrogen and ammonia. The proposed project will cover an area of 6,500 km^2 and cost an estimated $36 billion.

There are also several sites being considered along the West Coast of WA, which are closer to infrastructure and with the potential of proceeding in the shorter term. It is likely that only modest volumes of renewable sourced hydrogen will be required to be stored on a transitory basis in WA for the foreseeable future, and this has some bearing on the ideal storage method.

Non-renewable energy sourced hydrogen may add to the shorter-term storage requirements but are considered unlikely to alter the long-term requirements. This literature review and underground storage analysis is applicable to all hydrogen irrespective of its generation and source.

RISC has screened twenty-three onshore depleted gas and oil fields in WA for suitability to meet the storage need of renewable hydrogen and have identified seven fields as good candidates for hydrogen storage projects along the West Coast. RISC's mapping of renewable hubs relative to the subsurface sites shows that there is ample depleted oil/gas field storage capacity in the Perth Basin. However, the WGEH and the Asian Renewable Energy Hub are located over 1,000 km away from suitable depleted fields.

A more encouraging method of underground storage for the AREH project is subsurface salt. However, the Canning Basin which contains the thickest known salt deposits in Australia is distant (approximately 200 km). Unfortunately, no salt deposits have been mapped that are adjacent to the WGEH, although the Officer Basin 300 km north is reported to contain salt deposits.

RISC recommends that surface options are also considered as these may provide more effective solutions for renewable hydrogen storage in WA given the location of the renewable hubs relative to the subsurface sites and technical and environmental challenges.

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2. Terms of reference

The Government of Western Australia, Department of Mines, Industry Regulation and Safety ('DMIRS') commissioned RISC Advisory Pty Ltd ('RISC') to conduct a literature review and scoping study of hydrogen storage in depleted oil and gas fields in Western Australia ('WA') in the context of:

- The Government of WA has developed a renewable hydrogen strategy with the vision that WA will become a significant producer, exporter and user of renewable hydrogen.
- To achieve this vision, industry and markets need to be developed to enable the production, storage, export and use of renewable hydrogen.
- The Western Australian Renewable Hydrogen Roadmap (published in November 2020) includes the evaluation of utilising depleted oil and gas fields for hydrogen storage, with the first step being this review.

The agreed scope for the literature review was:

a. Comprehensive review of existing literature and status of research and technology of storing hydrogen in depleted hydrocarbon fields including identification of potential risks to storage of hydrogen.

b. High level review of literature of other examples of underground geological storage of hydrogen such as aquifer traps, salt caverns, underground mine sites and tunnels.

c. Commentary on the issues relating to creation of salt caverns across WA for hydrogen storage.

d. Discuss advantages and disadvantages and recommendations of various geological storage options.

e. The above to be carried out in consultation with key researchers on previous and ongoing work in the area of underground hydrogen storage, e.g. Geoscience Australia, CSIRO, Future Fuels CRC, as well as relevant companies involved in development of hydrogen energy.

Further discussion with DMIRS confirmed that:

- The review should also cover the potential to store hydrogen in salt caverns.
- The review will only cover storage requirement for renewable (green) hydrogen and not hydrogen produced from hydrocarbons where resultant CO_2 is released to the atmosphere (grey) or stored underground (blue). However, it is recognised that there may be a requirement for storage of grey and blue hydrogen.
- The aim would be to store the hydrogen on transitory basis and to be able to recover the hydrogen in high concentrations, rather than inject in low concentrations into hydrocarbon gas streams.

RISC also notes that there are alternative options for storing hydrogen on a transitory basis, such as surface and chemical methods. These would provide a useful comparison but are not included in the scope of this review.

A detailed bibliography as a result of the literature search is included as Appendix B – Bibliography.

As part of the study, RISC convened a virtual online workshop on 21 July 2021 with participants from CSIRO, Geoscience Australia, DMIRS, University of Edinburgh, Adelaide University, RAG and UEST in Austria. Details of attendees, agenda and presentations is included in Appendix C – Workshop presentation materials. The latest understanding of hydrogen storage from the workshop are integrated into our reported findings.

The agreed scope for the modelling scoping study was:

a. Review of the adequacy of available geoscience and engineering data (including geomechanical data) for model(s) development in a subsequent Stage 2.

b. Preliminary estimation of the storage capacity within all depleted fields based on hydrocarbons produced.

c. Review of depleted fields in the onshore northern Perth Basin and onshore Southern Carnarvon Basin within Western Australia to provide a seriatim of the fields to be modelled with respect to storage capacity and risks to storage.

d. Review of high-level risks and uncertainties and impacts on safe storage of hydrogen in onshore Perth Basin and Southern Carnarvon Basin depleted fields for consideration as part of the Stage 2 modelling.

e. Develop project specifications including high level work requirements, tasks and timelines for a Stage 2 modelling project.

The data and information used in the preparation of this report were primarily sourced from public domain information supplemented by data provided by DMIRS. RISC understands that the report will be made available to the public.

3. Literature database

There is no shortage of literature related to hydrogen storage. RISC's comprehensive literature search has identified over 300 relevant articles and papers (Figure 3-1). It is also relevant to point out that research into, and as a result the published literature, hydrogen generation and storage requirements is accelerating and becoming more significant.

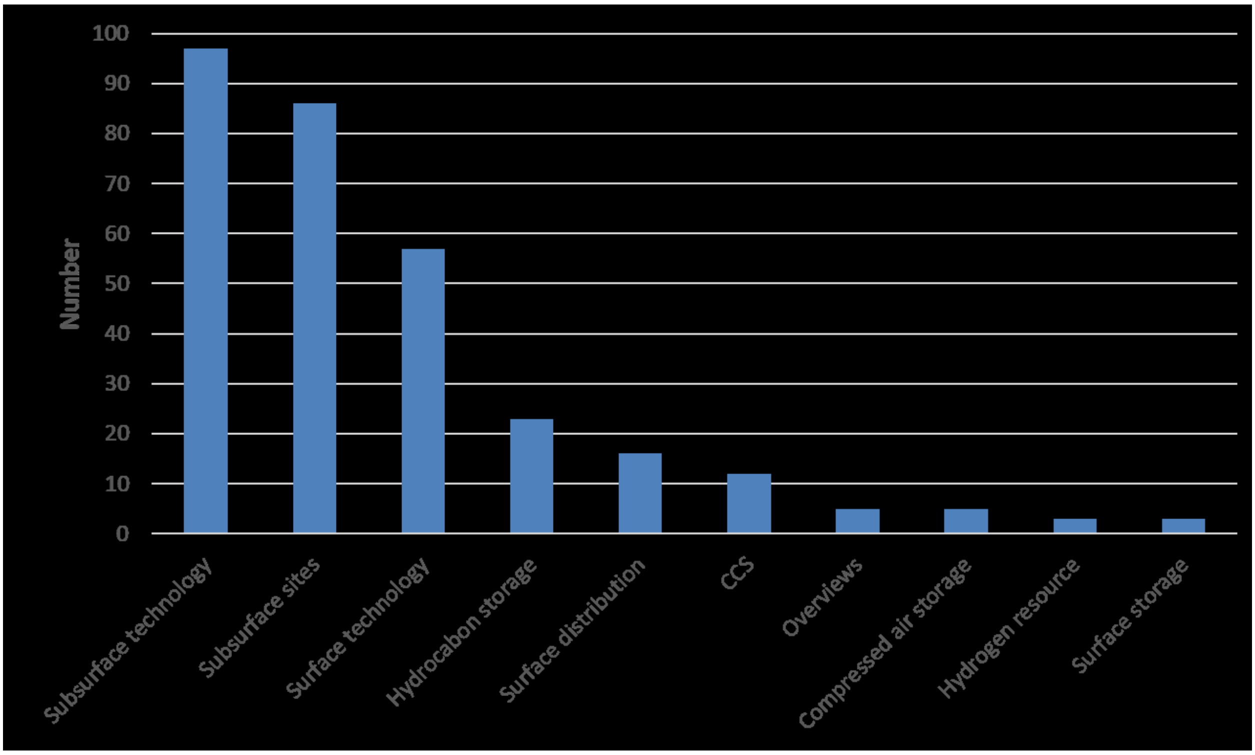

Figure 3-1: Hydrogen storage related articles

RISC has reviewed a subset of the available literature bearing some relevance to this study (Figure 3-2), although there is little literature directly related to hydrogen storage potential of depleted oil and gas fields worldwide, let alone in WA.

The global hydrogen industry (generation and use) in addition to its storage requirements is at an embryonic stage. However, this review provided useful context on how the hydrogen industry is developing. Aspirations and achievements of various countries (Germany, France, Denmark, Spain, UK, Canada and US) of what subsurface storage sites are being considered globally in addition to alternatives to subsurface storage (surface and chemical) have been reviewed.

A detailed bibliography of reference material is included as Appendix B – Bibliography.

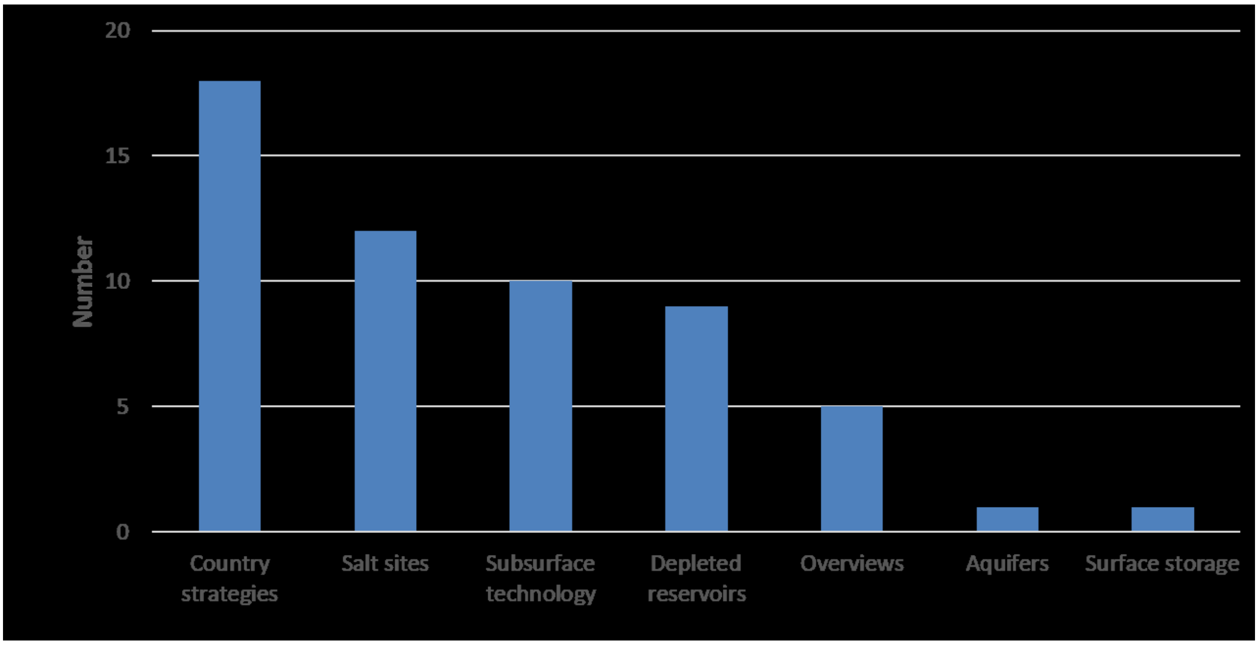

Figure 3-2: Hydrogen articles reviewed by RISC

4. Hydrogen subsurface storage overview

4.1. Characteristics

The focus of this review is on transitory storage of hydrogen generated primarily from renewable energy sources, which ideally satisfies the following criteria:

- **Safety**: Hydrogen is a highly flamable product and needs to be stored safely. Figure 4-1 shows that a wide range of hydrogen - air mixtures are explosive compared to other fuels.
- **Environment:** A key driver for renewable energy is to protect the environment by reducing greenhouse gas emmisions, primarily CO_2 emmisions. Any storage solution however needs to meet all envronmental requirements, including land-use and pollutants.
- **High recovery:** A major barrier to hydrogen production is cost. Any storage solution needs to be able to contain the hydrogen effectively and efficiently recover the stored hydrogen.
- **Technical challenges:** Ideally, the storage concept will be a proven solution and technical issues are addressed and/or minimised.
- **Minimal contamination:** The (stored and) recovered hydrogen should have minimal contamination (or dilution) due to the storage and recovery process.
- **Cycle time:** The cycle time of storing and recovering the hydrogen needs to be matched to business needs of the renewable energy sourced hydrogent plant. RISC expect this to be measured in weeks or months.

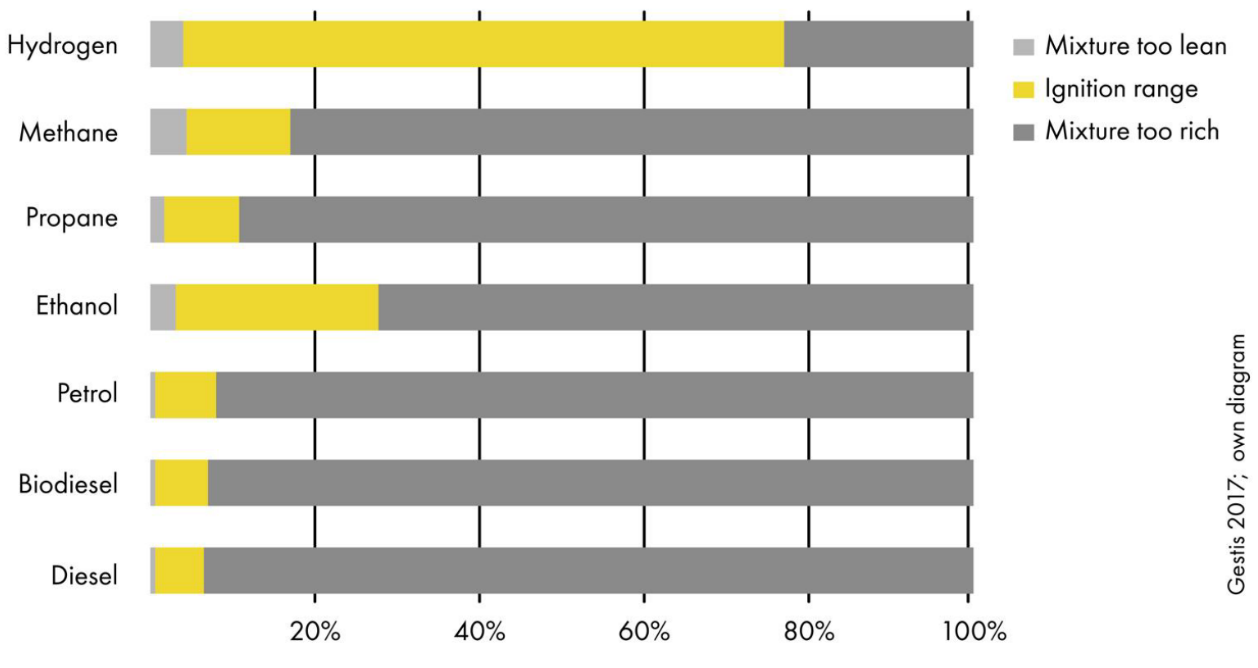

Figure 4-1: Ignition ranges of fuels with air [1]

[1] Shell hydrogen study; Energy of the future?, 2017.

The Australia National Hydrogen Roadmap[2] sets underground storage in context with alternate mature hydrogen storage technologies (Table 4-1).

Table 4-1: Mature hydrogen storage technologies [2]

TECHNOLOGY	DESCRIPTION[48, 49]	DIS/ADVANTAGES
Compression		
Low pressure tanks	No additional compression needed from hydrogen production. Only used for stationary storage where lower quantities of hydrogen are needed relative to available space.	+ Established technology - Poor volumetric energy density
Pressurised tanks	A mechanical device increases the pressure of the hydrogen in its cylinder. Hydrogen can be compressed and stored in steel cylinders at pressures of up to 200 bar. While composite tanks can store hydrogen at up to 800 bar[49], pressures typically range from 350 to 700 bar. Compression is used for both stationary storage and transport of hydrogen.	+ Established technology - Low volumetric energy density - Energy intensive process
Underground Storage	Hydrogen gas is injected and compressed in underground salt caverns which are excavated and shaped by injecting water into existing rock salt formations.[50] Withdrawal and compressor units extract the gas when required.	+ High volume at lower pressure and cost + Allows seasonal storage - Geographically specific
Line packing	A technique used in the natural gas industry, whereby altering the pipeline pressure, gas can be stored in pipelines for days and then used during peak demand periods.	+ Existing infrastructure + Straightforward hydrogen storage technique at scale
Liquefaction		
Cryogenic tanks	Through a multi-stage process of compression and cooling, hydrogen is liquefied and stored at -253°C in cryogenic tanks. Liquefaction is used for both stationary storage and transport of hydrogen.	+ Higher volumetric storage capacity + Fewer evaporation losses - Requires advanced and more expensive storage material
Cryo-compressed	Hydrogen is stored at cryogenic temperatures combined with pressures approaching 300 bar.	+ Higher volumetric storage capacity + Fewer evaporation losses - Requires advanced and more expensive storage material
Material based		
Ammonia (NH_3)	Hydrogen is converted to ammonia via the Haber Bosch process. This can be added to water and transported at room temperature and pressure. The resulting ammonia may need to be converted back to hydrogen at the point of use.	+ Infrastructure is established + High hydrogen density (17.5% by weight) - Almost at theoretical efficiency limit - Plants need to run continuously - Energy penalty for conversion back to hydrogen - Toxic material

4.2. Predicted hydrogen production and demand for storage

Underground hydrogen storage is in its infancy, but the characteristics will be similar to the storage of natural gas, which is routinely used in the US, Europe and Australia to modulate seasonal heating demand, back-up power generation and reduce dependency on imports. The temporal nature of generation of renewable energy adds to the need for transitory storage of hydrogen.

[2] National Hydrogen Roadmap, CSIRO, 2018.

The predicted global hydrogen production provided in the literature generally does not distinguish between renewable (green) hydrogen, hydrogen produced from hydrocarbons where resultant CO_2 is released to the atmosphere (grey) or stored underground (blue). RISC expect the 'green' hydrogen to be a moderate proportion, so we need to bear this in mind when placing the WA renewable hydrogen storage demand in context.

The expected demand for large scale storage of hydrogen in Europe was presented at the United Nations Framework Classification ('UNFC') resource management week in April 2021 and is summarised in Table 4-2. These forecasts assume that the storage requirement is 10-20% of annual production, consistent with 2019 natural gas storage utilisation. The estimated storage figures are significant, with the study predicting up to 5 Tcf of hydrogen storage is required in Europe by 2050.

The UNFC presentation does not however provide the basis or background to the estimates and RISC expect that there will be included a significant proportion of 'blue' or 'grey' hydrogen. In any event, we can expect significant development of hydrogen subsurface storage knowledge and capabilities in the coming years.

Table 4-2: Expected European demand for large scale hydrogen storage [3]

Resource	Natural Gas			Hydrogen		
	Demand (Bcm)	Storage (Bcm)	Percentage	Demand (TWh)	Assumed Storage	Storage requirement (Bcm)
Global 2019	3,986	483	12%			
Europe 2019	470	105	22%			
Europe 2030				481 - 665	10 - 20%	16 - 44
Europe 2050				780 - 2,251	10 - 20%	26 - 150

Notes to the table:
1 Bcm = 35.31 Bcf

[3] Resource Management Week - Application of UNFC injection projects, April 2021.

5. Subsurface systems

5.1. Introduction

There are two basic underground storage systems suitable for hydrogen; salt caverns or in porous media (subsurface reservoir). Salt caverns are manufactured by pumping water into the salt body to create a cavern, while porous media may be either depleted gas and oil fields or aquifer traps (Figure 5 1). Each system has its own characteristics when compared to transitory storage criteria.

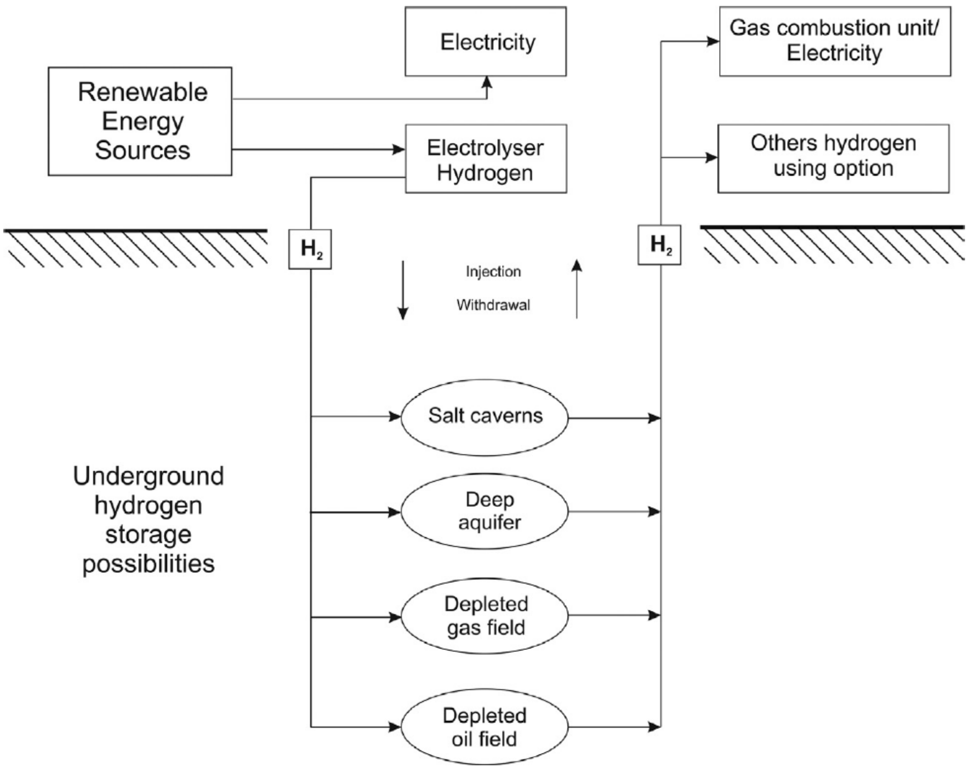

Figure 5-1: Schematic underground storage systems [4]

RISC's high-level assessment of the different storage systems against the storage criteria is given in Table 5-1.

Salt caverns are considered the best technical solution. They are a proven concept in underground storage, with a demonstrated safety record and fast cyclic storage. Salt acts an excellent seal making them effective and safe and the caverns themselves can be designed to fit the storage requirements. There are also no other residual native gases or hydrocarbons to mix with and potentially contaminate the stored hydrogen. The main issue is the distance of suitable salt from renewable energy sites. Water supply and resultant brine disposal are issues, particularly in WA where there is typically a shortage of water and limited means of brine disposal other than subsurface injection.

All porous media systems carry uncertainties and risks due to the inherent technical complexity. The technical viability is still to be proven and long lead times (10 - 15 years) are expected for demonstration and development.

[4] Underground hydrogen storage: characteristics and prospects, Radoslaw Tarkowski, 2019.

Table 5-1: Subsurface storage systems characteristics

Criteria	Salt caverns	Aquifer Traps	Depleted gas field	Depleted oil field
Safety	Good	Fair	Fair	Fair
Environment	Moderate/poor	Fair	Fair	Fair
Recovery	Good	Site dependent	Site dependent	Site dependent
Technical challenges	Low	High	High	High
Contamination	Excellent	Good	Moderate	Poor
Cycle time	Excellent	Site dependent	Site dependent	Site dependent
Location	Site dependent	Site dependent	Site dependent	Site dependent
Experience/risk	Moderate	Poor	Poor	Poor

There are only a handful of hydrogen subsurface sites currently in operation worldwide (Table 5-2). Of these, only four are used to store hydrogen in high concentrations, all of which are in salt caverns. The storage volumes are quite modest relative to the capacity of oil and gas fields, except for the Benyes field in France which is used to store synthetic 'town' gas which consists of a mixture of hydrogen, methane and carbon monoxide.

Table 5-2: Current hydrogen subsurface storage sites

Country	Field	Storage type	Depth (m)	Pressure (Bar)	H_2 %	Volume (MMscf)
USA	Spindletop	Salt cavern	1340	Confidential	95	31.8
USA	Clemens Dome	Salt cavern	800	70-135	95	20.4
USA	Moss Bluff	Salt cavern	800	55-152		19.9
UK	Teeside	Salt cavern	350-400	45-50	95	7.4
France	Beynes	Aquifer trap			50	11,583
Germany	Keil	Salt cavern		80-100	60	1.1
Germany	Ketzin	Aquifer trap			62	
Czech Republic	Lobodice	Aquifer trap		90	50	
Argentina	Diadema (HyChico?)	Depleted gas reservoir		10	10	
Austria	Underground Sun Storage (RAG)	Depleted gas reservoir		78	10	

Notes to the table:
1 MMscf = 0.001 Bcf

The details of the four hydrogen storage salt caverns in the world are provided in Figure 5-2.

Localisation	Clemens Dome (US)	Moss Bluff (US)	Spindletop (US)	Teeside (UK)
Operator	Conoco Philips	Praxair	Air Liquide	Sabic
Start	1983	2007	2014	1972
Volume (10^3 m^3)	580	566	>580	3*70
Pressure (bar)	70-135	55-152	Confidential	45
Energy (GWh)	92	120	>120	25

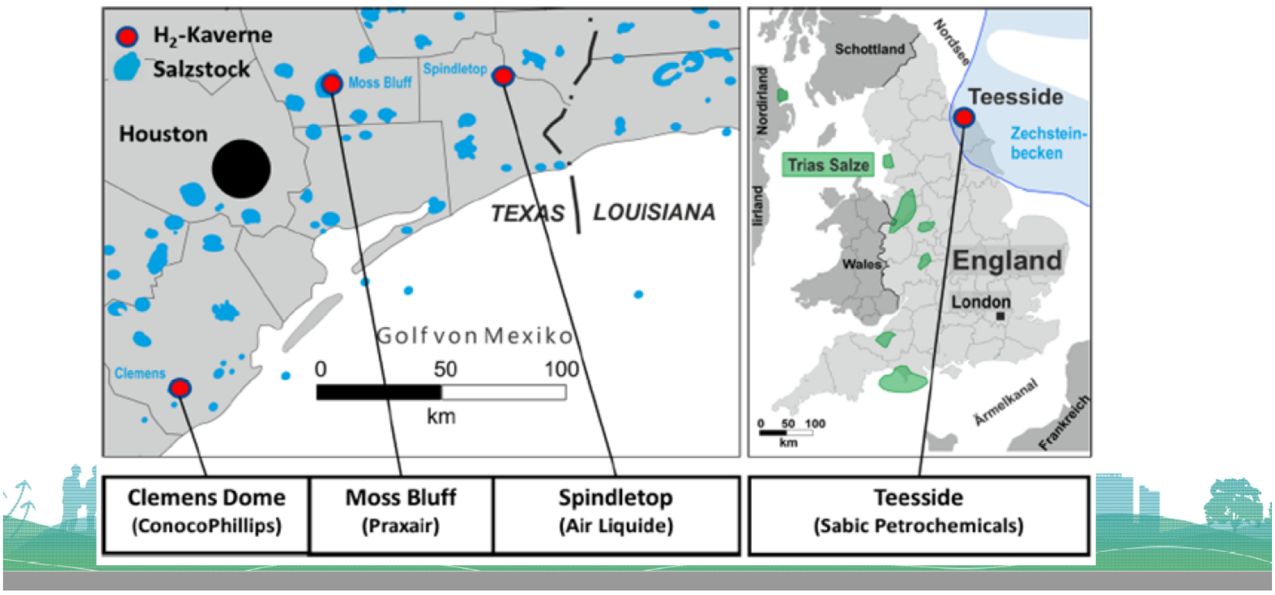

Figure 5-2: The 4 hydrogen storage salt caverns in the world [5]

A number of additional sites worldwide are being considered to store hydrogen (Figure 5-3). The majority of which are in salt (classified as salt caverns in Europe and salt domes in the US), but with a number in aquifer traps and depleted gas and/or oil fields. There is no information on the expected concentration of hydrogen in these sites.

Some of the global pilot & demonstration underground hydrogen storage projects underway are:

- RAG – SunStorage (Austria – gas field)
- HyChico (Argentina – gas field)
- Energystock - HyStock (Netherlands – salt cavern)
- Storengy - HyPster (France – salt cavern)

[5] Storengy: European Workshop on Underground Energy Storage, November 2019.

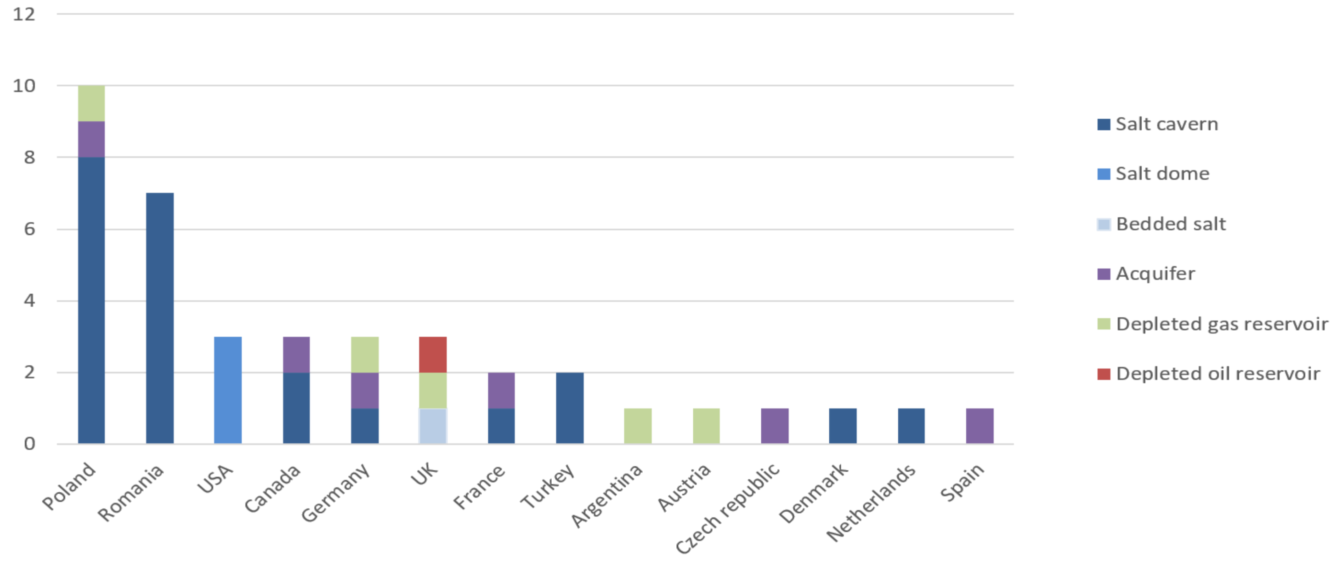

Figure 5-3: Hydrogen sites under consideration [6]

There are also several subsurface mapping, characterisation & screening projects underway worldwide:

- Various national appraisal and feasibility studies
- H2020 – HyUnder (potential/actors/business cases for large scale underground hydrogen storage in Europe)
- H2020 – ESTMAP (European Energy Storage Mapping and Planning)
- H2020 – HyStorIES (Underground storage of renewable hydrogen in depleted gas fields and other geological stores)
- Horizon-Europe call – CSA Geological Services for Europe > EU database and atlas for underground storage (CCS/Heat/Energy)

The DMIRS initiative is aligned with these ongoing global developments. RISC have not found any literature regarding storage of hydrogen in underground mine shafts or tunnels. RISC estimate that these would be less attractive options to salt or depleted fields due to retention issues and the risk of leakage, unless they are located within a salt body.

5.2. Salt caverns

Salt caverns are created through the process of solution of the salt with pumped water (Figure 5-4). This process requires an abundant water supply, and the subsequent brine needs to be disposed of safely and in an environmentally acceptable manner. The hydrogen is then injected and stored under pressure and then recovered by releasing the pressure within an operational pressure range. Operationally, the caverns are efficient as the size can be customised to the operational requirements, they have a relatively high recovery and an injection/production cycle time in the order of days to weeks. The salt also acts as an excellent seal and any fractures or cracks will anneal or seal over time due to the relative mobility of the salt.

Salt caverns are routinely used throughout the world to store hydrocarbon gas, liquids and LPG. A map of these sites throughout Europe is shown in Figure 5-5.

[6] Data compiled from 'Underground hydrogen storage: A comprehensive review, Davood Zivar et. al. March 2020'

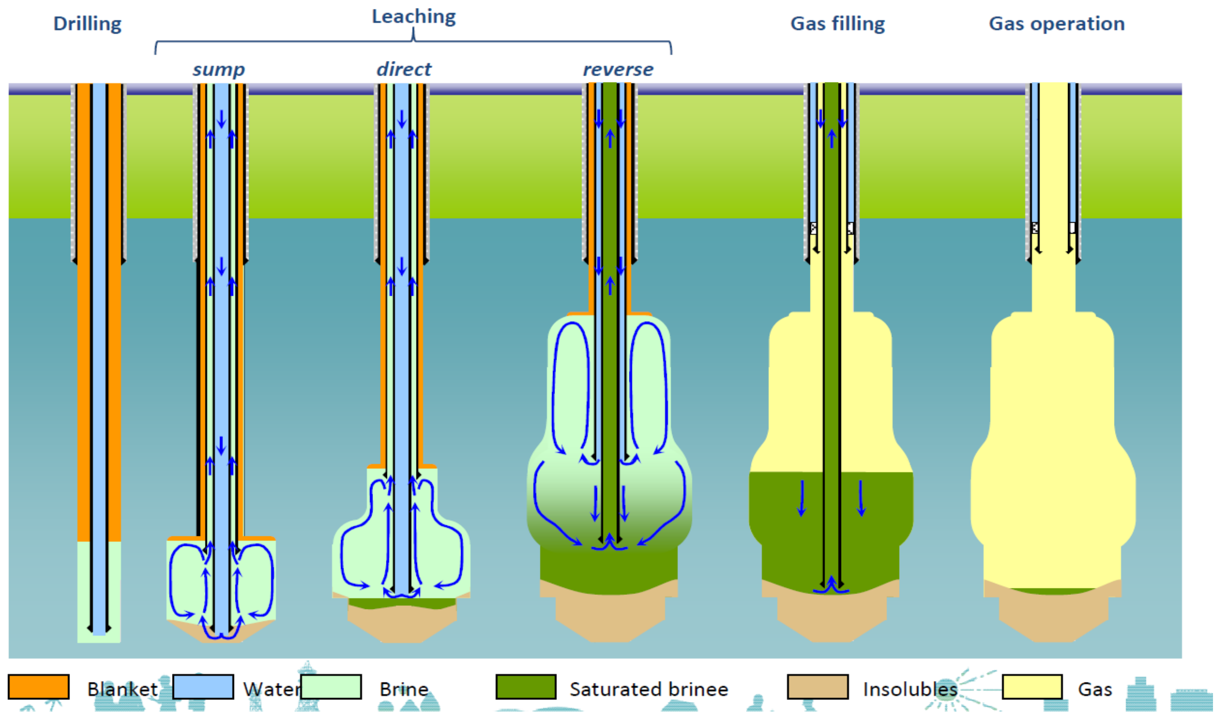

Figure 5-4: Steps in salt cavern creation [7]

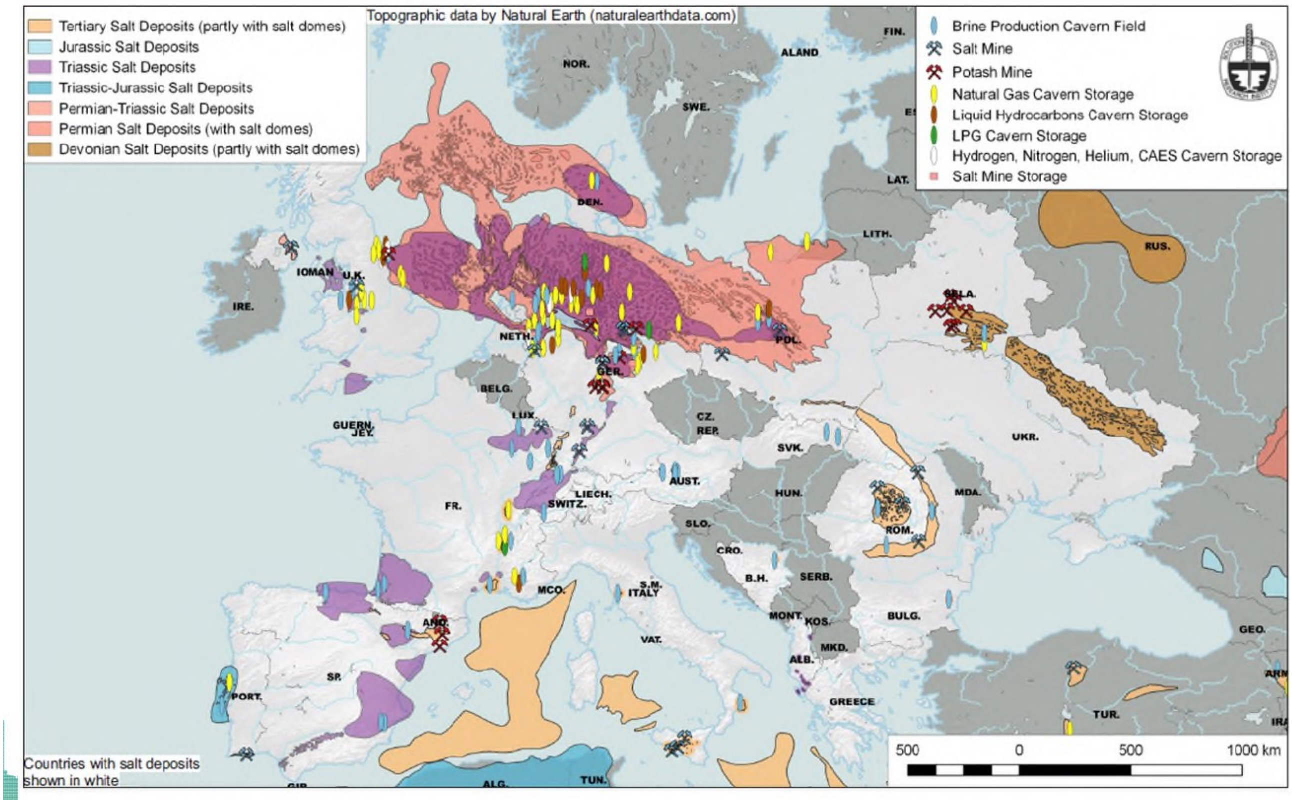

Figure 5-5: Salt deposits and caverns in Europe [7]

[7] Storengy: European Workshop on Underground Energy Storage, November 2019.

An underground storage database[8] captures over 140 salt caverns across 17 countries that store hydrocarbon gas, with volumes ranging from less than 0.2 Bcf to over 200 Bcf (Figure 5-6).

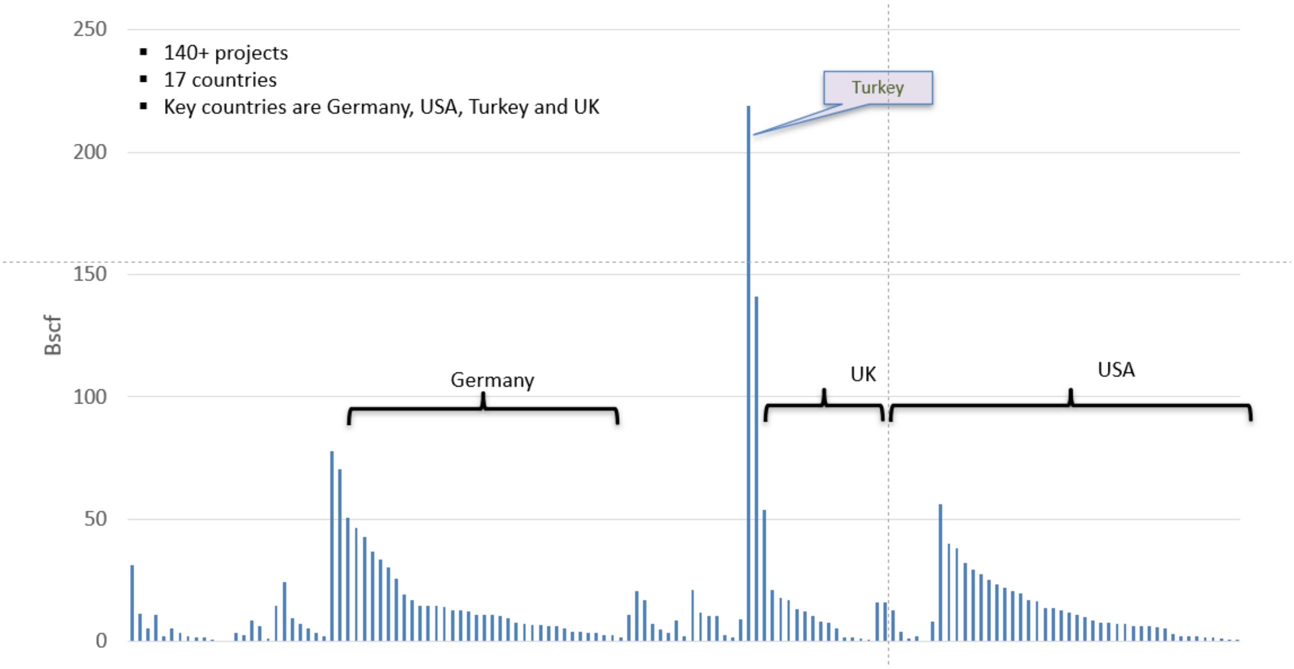

Figure 5-6: Global salt cavern gas storage sites [8]

The key challenges for storage of hydrogen in salt caverns are:

- As in depleted oil and gas fields, microbial activity is a potential issue in salt, that can result in souring of the stored gas with H_2S.
- Water supply and brine disposal may be challenging. This is particularly true in the generally arid areas of WA. However, deeper limited salinity aquifers are likely to be available.
- The creation of salt caverns will require the drilling of several wells and take many months.
- Suitable salt formations may not be adjacent to the desired hydrogen storage location and require additional pipelines and compression for hydrogen transport.
- Shallow salt caverns can cause geomechanical issues such as overburden collapse and minor earthquakes. Salt caverns created for gas storage would be deeper to allow higher pressure and greater storage volume and thereby should avoid such issues.

5.3. Porous media

5.3.1. Introduction

The storage of hydrogen in porous media is potentially more complex than hydrocarbon gases or CO_2. Town gas (or coal gas) has been stored in large scale underground storage and is a mixture of approximately 50% hydrogen, 25% methane, 14% carbon monoxide and smaller components of other gases. There are no examples of storing pure (95%$^+$) hydrogen in porous media, although a gas storage company in Austria (RAG Austria) is planning to start a pure hydrogen storage trial shortly.

[8] IGU: Underground Gas Storage Database for the WGC 2022.

The physical behavior and properties of hydrogen are significantly different to natural gas. It has a lower density and so higher storage pressures are required to store the same mass. The low density also makes hydrogen four times more diffusive than methane, making it more susceptible to leakage. Hydrogen is also more chemically reactive and can interact with clay minerals or other reservoir and caprock minerals, which may in turn affect aspects of reservoir quality such as porosity or permeability.

Hydrogen is also an energy source for subsurface microbial processes, such as methanogenesis, sulfate reduction, and acetogenesis, and have been shown to occur at temperatures up to 90 °C and in low to medium water salinities. Hydrogen can also react with CO_2 to form methane. These mechanisms were identified as concerns at a site in Lobodice, Czech Republic, where approximately half of the hydrogen in stored town gas (45 - 60% H_2) was transformed into methane or hydrogen sulfide through microbial activity. These impact the hydrogen storage cycle from site selection to storage site operation and a multidisciplinary approach, including reservoir engineering, chemistry, geology and microbiology, is required to implement safe, efficient storage.

The key uncertainties with storing hydrogen in porous media are illustrated in Figure 5-7. Storage in depleted gas and oil fields will have the additional complication of remaining oil and gas which may interact with and contaminate the hydrogen.

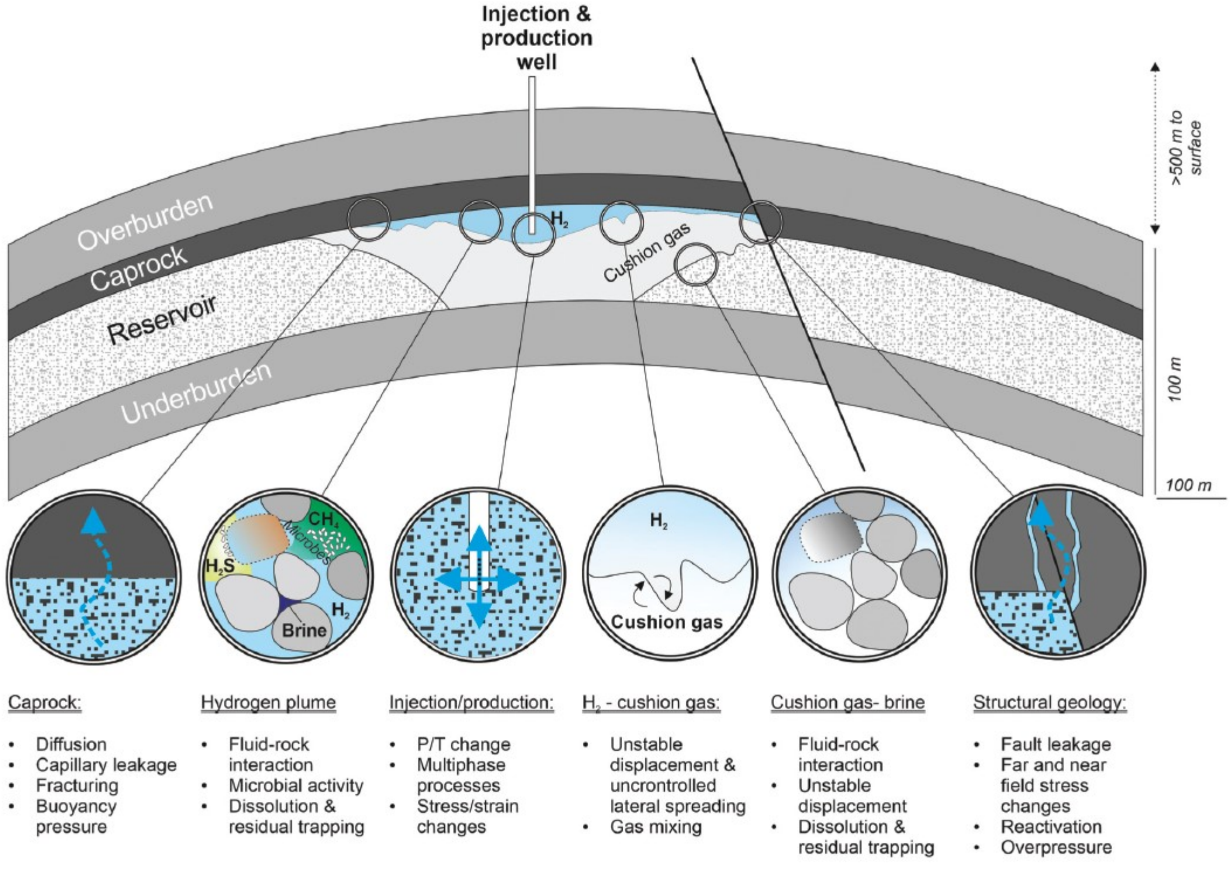

Figure 5-7: Uncertainties of hydrocarbon storage in porous media [9]

[9] Enabling large-scale hydrogen storage in porous media, Niklas Heinmann et. al. Energy Envirn. Sci, 2021.

Other issues to consider are the appropriate size of the structure and cycle time. Our research indicates that depleted oil and gas fields are larger than the expected volumes of hydrogen to be stored, suggesting that recovery efficiency will be low i.e. significant volumes of the hydrogen will be required as cushion gas[10]. There is considerable experience in transitory storage of hydrocarbon gas in porous media and cycles times are in the order of 1-2 storage cycles per year, due to permeability and size of the structures.

5.3.2. Issues relating to hydrogen storage in depleted oil and gas fields

A number of reactions may occur when hydrogen gas is injected into depleted oil and gas fields which may reduce the proportion of hydrogen that can be re-produced and cause potential contamination of the re-produced hydrogen:

- Hydrogen being highly reactive may react with the cap-rock and reduce reservoir seal capacity. Often not a risk but depends upon kerogen content and competency of the cap-rock.
- Hydrogen may also react with the reservoir formation and not be recoverable. Analysis undertaken to date[11] indicate this is a low risk.
- Microbial action may sour the stored hydrogen with H_2S. Elevated temperatures (>90 °C) and elevated water salinity (>4 moles NaCl per kg of water) is shown to prevent microbial action[11]. The risk and degree of microbial action below these limits is unknown and requires further evaluation.
- Hydrogen reacts with CO_2 to form methane.
- Hydrogen will mix with any gas remaining in the gas reservoir and the re-produced gas will be a mixture of hydrocarbon gas and hydrogen. The degree of mixing is an uncertainty, but initial data suggest limited mixing of hydrogen with natural gas by managing the rate and location of hydrogen injection.
- Hydrogen will dissolve in formation water in the reservoir and may not be recoverable. However, the solubility of hydrogen in water is estimated to be minor. Note the re-produced hydrogen will be wet and require drying.
- Hydrogen will dissolve in oil remaining in an oil reservoir and may not be recoverable. This volume can be significant.
- Hydrogen can be lost as residual gas in depleted gas reservoir with aquifer drive and in aquifer traps.

Greater hydrogen losses are likely in depleted oil fields compared to depleted gas fields due to the solubility of hydrogen in the oil and hydrogen forming unrecoverable residual gas in oil fields. Therefore, depleted oil fields are only likely to be of interest for storage if depleted gas fields are not available.

5.3.2.1. Solubility of hydrogen in water and oil

The solubility of hydrogen in water increases with temperature and pressure but reduces in more saline water (Figure 5-8).

At typical reservoir conditions of 70 bara and 333 kelvin the solubility of hydrogen in fresh water is about 0.001 mole fraction which is 111 mg/kg, reducing to 0.0007 mole fraction (78 mg/kg) in saline water with 1 mole of NaCl per kg of water. Therefore, the solubility of hydrogen in water at reservoir conditions remains small.

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[10] Cushion gas, or base gas, is the volume of gas required in gas storage applications to maintain adequate reservoir pressure and conditions to ensure deliverability and operational requirements.

[11] Edinburgh University HystorPor project; https://eartharxiv.org/repository/view/1799/

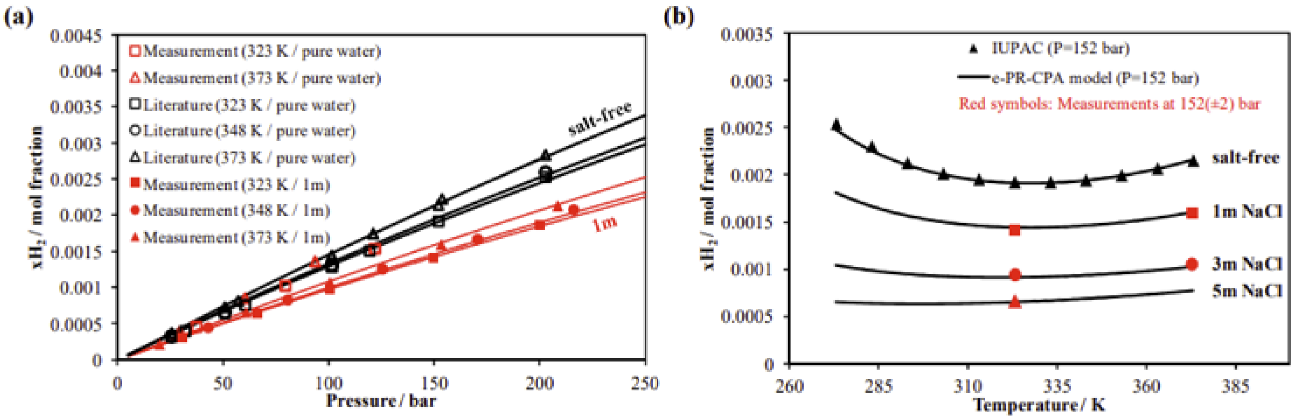

Figure 5-8: Solubility of hydrogen in water and brines [12]

Regular solution theory can be used to estimate the solubility of hydrogen in various hydrocarbons at different temperatures and pressures. The data solubility series[13] shows the solubility of hydrogen in a benzene, cyclobenzene and hexane mixture at typical reservoir temperatures and pressures. At 93 °C and 71.2 bara the dissolved hydrogen is 0.1% by weight or 1000 mg/kg which correlates to approximately 800 mg per litre of oil. Each million barrels of oil remaining in the reservoir could therefore dissolve 130 tonnes of hydrogen, although this would depend upon the degree of mixing of hydrogen with the oil. Potential hydrogen losses through dissolution in oil reservoirs may therefore be significant.

5.3.2.2. Residual trapped hydrogen

In reservoirs with a water drive, aquifer water influxes into the reservoir as the hydrocarbons are produced. The imbibing water traps residual hydrocarbon that becomes immobile (trapped) and not produced. When gas (natural gas or hydrogen) is re-injected or stored in the reservoir, the influxed aquifer is pushed back to accommodate the gas. When this stored gas is reproduced, the aquifer influxes again and re-traps residual gas. Residual gas saturations are in the order of 25% of the pore volume where water encroaches.

This does not affect natural gas storage in depleted gas fields as the residual gas trapped upon the re-production of the stored gas is the same natural gas that was trapped on the initial field depletion. However, if hydrogen is stored, the trapped gas may be a mixture of native reservoir gas and hydrogen. Therefore, some hydrogen may be lost as residual gas.

Hydrogen is a lighter gas and likely to remain at the top of the depleted gas reservoir. Therefore, the volume of hydrogen trapped by water may therefore be limited. Vertical segregation of hydrogen and native gas in the gas reservoir may also limit the contamination of re-produced hydrogen with natural gas.

When water bearing traps (aquifers) are used for gas storage, the aquifer must be sufficiently mobile to be displaced to allow gas injection. The aquifer will re-influx when the hydrogen is reproduced, and some hydrogen will be therefore lost as residual gas. This can be a significant volume (25%) of hydrogen loss. The use of a less valuable gas such as nitrogen or CO_2 as cushion gas followed by hydrogen injection is being considered. However, this introduces the risk of contamination of re-produced hydrogen with the cushion gas.

[12] Measurements and predictive models of high-pressure H2 solubility in brine (H2O+NaCl) for Underground Hydrogen Storage application (1 Nov 2020).
[13] Solubility Data Series Volume 5/6 hydrogen and deuterium, International Union of Pure and Applied Chemistry.

If depleted oil fields are used for hydrogen storage, hydrogen may be lost as residual gas if the oil influxes back into the pore volume when hydrogen is re-produced. If the oil field has a gas cap and the gas cap is used for hydrogen storage this issue is partially alleviated.

5.3.2.3. Contamination of hydrogen with natural gas

A key concern with storing hydrogen in depleted natural gas fields is the mixing and contamination of pure hydrogen with natural gas. This may lead to hydrogen losses in the native and/or cushion gas in addition to a potential requirement for recovery and separation processes when the hydrogen is reproduced.

Preliminary findings suggest that the degree of mixing may be limited if hydrogen injection is managed; namely:

- Modelling indicates limited Boolean mixing occurs in the storage timeframes and re-produced gas is largely the injected gas.
- RAG Austria's experience storing 10% hydrogen in a natural gas storage reservoir is that mixing is limited and good hydrogen recovery occurs.
- Hydrogen injection rates should be limited to avoid viscous fingering into the less mobile native hydrocarbon gas column.

Selecting the appropriate field size for the volumes of hydrogen storage required should reduce mixing and hydrogen losses:

- Additional cushion gas will be required in over-sized fields.
- The volume of remaining hydrocarbon gas to stored hydrogen is minimised in appropriately sized fields. This should reduce potential mixing.

The geological nature of the field will also affect hydrogen losses and potential mixing:

- Steeply dipping structures with hydrogen injection at the crest may reduce mixing.
- Permeable reservoir will allow hydrogen to be injected in the crest of the structure. If the crest of the field has poor quality reservoir, hydrogen may inject into the more permeable intervals, with gravity and buoyant forces causing mixing with native hydrocarbons.

Specific field modelling is required to quantify potential hydrogen natural gas mixing.

5.3.3. Aquifer traps

To store and retrieve gas in a deep confined aquifer, there must be a trap in the traditional petroleum sense to retain the stored gas. As the trap is not known to contain hydrocarbons there is no proof that the trap is effective; i.e. that is sealing. Therefore, storing hydrogen gas in aquifer bearing traps carries the risk of retention and potential leakage.

The use of shallow unconfined aquifers and potable water aquifers would not be environmentally acceptable nor technically feasible.

Hydrogen loss as a residual gas has already been discussed and is applicable in aquifer traps.

6. Western Australia's future hydrogen storage requirements

There are numerous renewable energy projects with associated hydrogen generation currently being considered or evaluated in Western Australia ('WA'). The largest being the Western Green Energy Hub ('WGEH') and the Asian Renewable Hub ('AREH'), which are considered world scale.

The WGEH would be located in the south-east of WA with the aspiration to generate up to 50 GW of solar and wind generation over an area of 15,000 km^2. The AREH is under consideration by a consortium of energy companies (InterContinental Energy, CWP Global and Vestas) in the East Pilbara, with a plan for 6,500 km^2 in solar and wind generation and cost an estimated $36 billion. It aspires to 26 GW of wind and solar generation, with up to 23 GW of generation for production of green hydrogen and green ammonia.

Hydrogen Renewables Australia ('HRA') is proposing to develop the Murchison Renewable Hydrogen project just north of Kalbarri, WA. It would aim to develop a combined wind and solar farm that will operate at 5,000 MW and produce low-cost renewable hydrogen. The project is in the early stages, but HRA have undertaken preliminary discussions with key representatives of the WA and Commonwealth Governments, the local Northampton Shire Council, the local Nanda Aboriginal Corporation and several other key local stakeholders.

ENGIE and YARA have also partnered to evaluate the Renewable Hydrogen and Ammonia Deployment ('YURI') plant that would produce renewable hydrogen near Karratha which in turn will be used to develop ammonia. YARA operates ammonia and fertiliser plants in the Pilbara region of WA and ENGIE is global leader in low carbon energy and services. The plant aspires to operate at up to 2 GW by 2030. While there will be no requirement to store the hydrogen in the subsurface, RISC have included it for context.

RISC has estimated order of magnitude maximum possible hydrogen subsurface storage requirements for all the renewable energy projects known at the time of writing, which is shown in Figure 6-1.

RISC acknowledge that the numbers are approximate and set an upper limit. RISC have assumed:

- All of the stated target capacity would be used to generate hydrogen, whilst some will be used as a feedstock for ammonia.
- The renewable energy plants will operate at 30 - 50% annual capacity, consistent with periodic supply of solar and wind power.
- The storage capacity would be 30% of annual production (EU gas storage is 10-20% of annual production).

While the WGEH and Asia Renewable Hub could require substantial volumes, the nearer term projects are considered to have a much more modest storage requirement.

For reference, the estimated hydrogen demand in the United Kingdom is up to 22 TWh (Figure 6-2). Assuming this requires 30% storage the storage volumes is 6.6 TWh or 78 Bcf. This storage volume is considered consistent with the smaller, nearer term WA project or hub volumes.

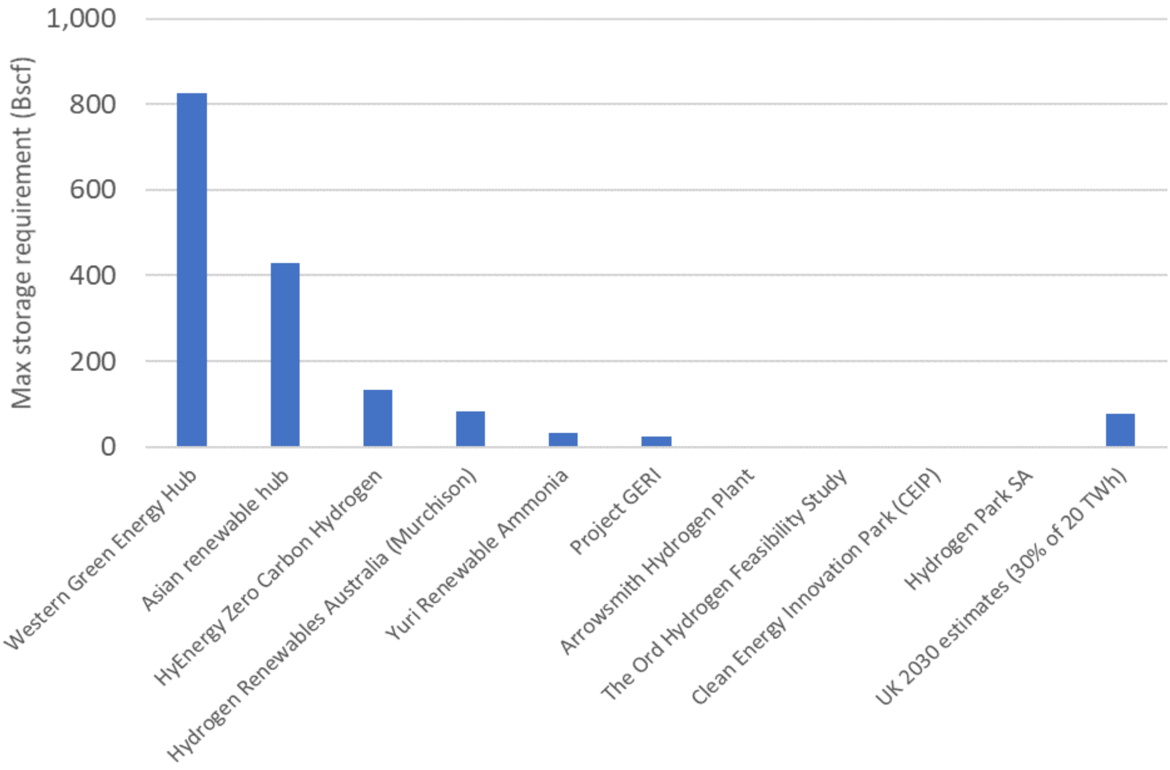

Figure 6-1: Maximum hydrogen storage requirements for proposed WA renewable hubs

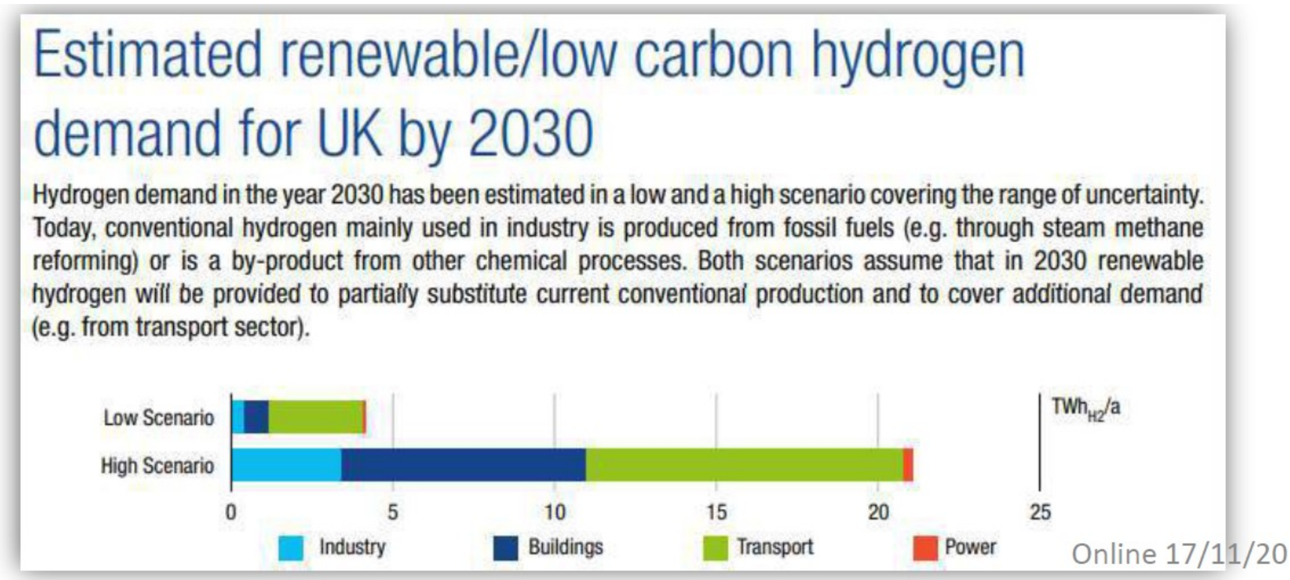

Figure 6-2: UK renewable hydrocarbon demand [14]

[14] HyStorPor Industry Workshop Nov 2020

For WREH and AREH, RISC have scaled the costs for the most up to date stated target capacities for the project, noting the huge investments required (Figure 6-3). There are no similar numbers for United Kingdom storage estimates, in addition there are no costs publicly available.

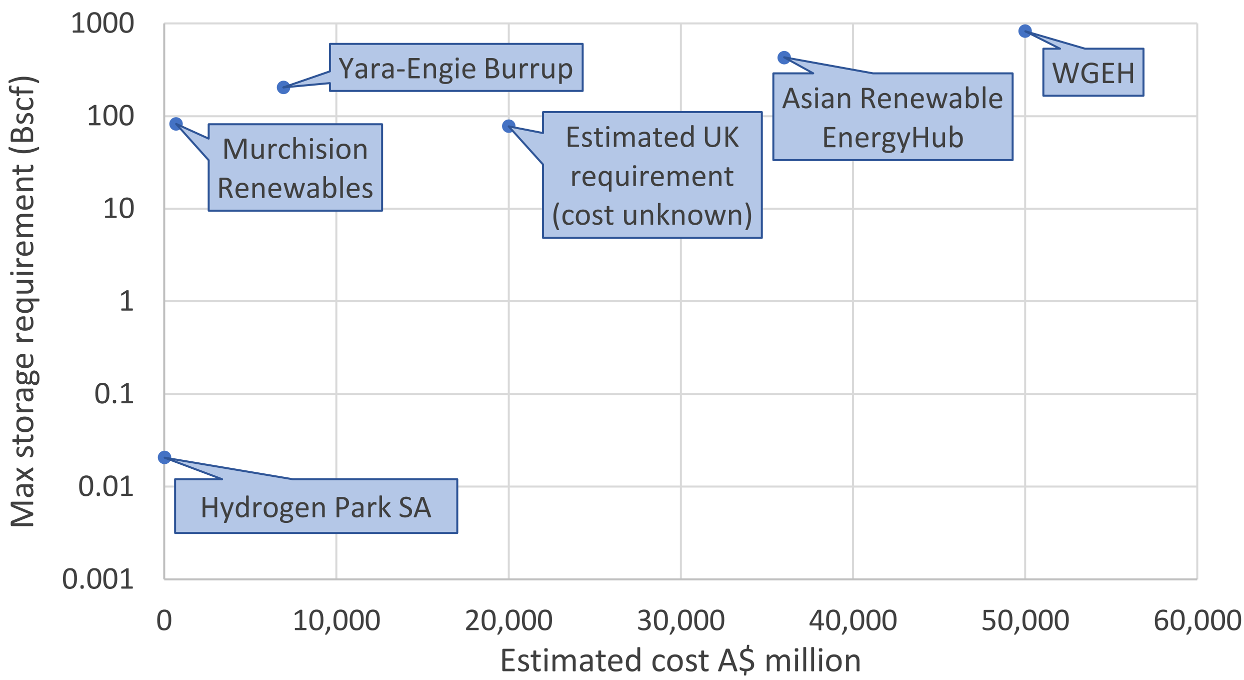

Figure 6-3: Maximum hydrogen storage requirements for Australia renewable projects

The proposed projects in the Perth Basin and West Coast of WA are smaller hydrogen projects that are more likely to progress in a reasonable timeframe and require an estimated storage capacity of 5 to 50 Bcf, more in line with the USA and European sites (Figure 6-4). These projects are located close to existing infrastructure and depleted oil and gas fields which could be considered for transitory hydrogen storage.

The Mega projects such as WGEH and AREH are remote and not favourably located with respect to depleted fields for storage and may be more difficult to progress due to the investment required.

In either case the storage volumes required are substantially greater than a typical LNG storage tank capacity from the NWShelf and therefore underground storage is a more feasible option (refer Figure 6-4).

In summary, RISC estimates that the demand for hydrogen storage in WA will be 5 to 50 Bcf and this storage would ideally be distributed across a number of locations adjacent to the various hydrogen projects. Individual site storage requirements are likely to be a few Bcf. Larger hydrogen storage sites (>10 Bcf) may be desirable if and when extensive hydrogen pipeline networks are established.

Field size is a consideration when ranking depleted oil and gas field for hydrogen storage applicability. Fields with a storage capacity of a few Bcf have advantages over larger field in that the mixing of estimated hydrogen storage volumes with remaining gas will be reduced and cushion gas potentially required for hydrogen storage operations is reduced.

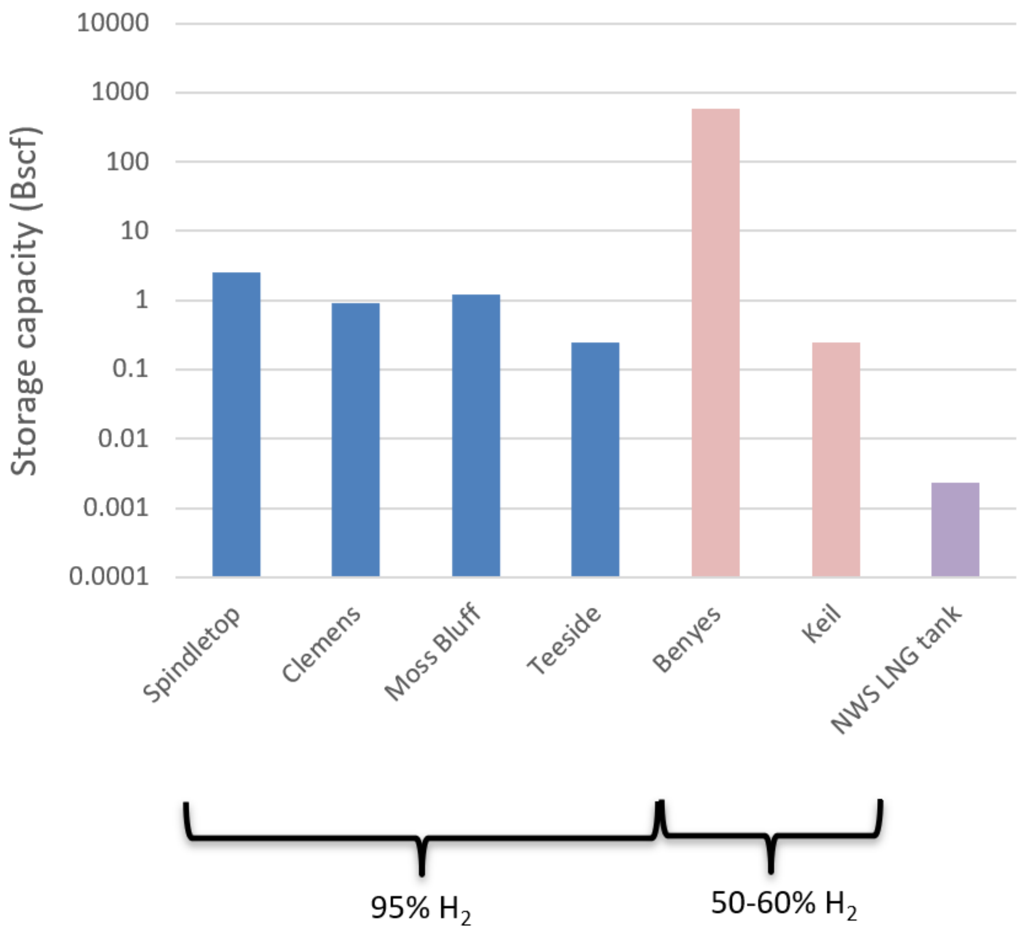

Figure 6-4: Existing hydrogen subsurface storage project capacities, and comparison to an LNG tank

7. Western Australia storage opportunities

7.1. Depleted oil and gas fields

In accordance with the scope of the project, RISC has reviewed several shut-in oil and gas fields in the onshore Perth and Carnarvon Basins, Western Australia, many of which are classified as depleted. In total, RISC considered 23 fields, with 21 of these fields located in the Perth Basin. Our screening identified several candidates, with the Dongara field dominating in terms of potential storage volume (Figure 7-1).

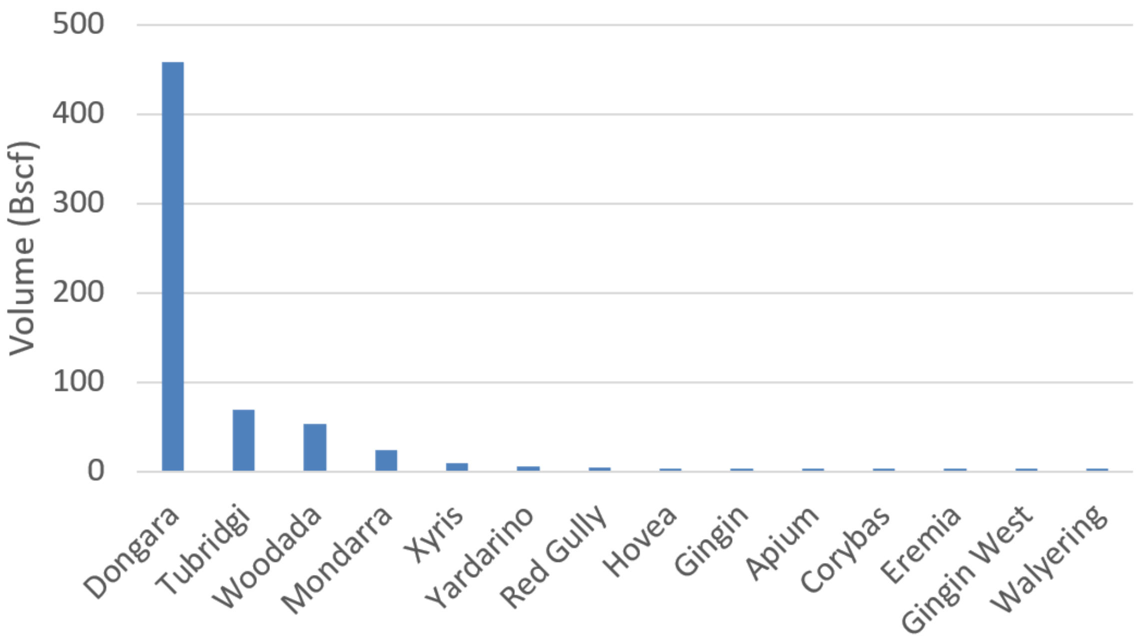

Figure 7-1: Depleted oil and gas fields in WA with potential for hydrogen storage

The fields were initially screened through a review of the WAPIMS open file data and documentation in addition to other public domain information where available. This included:

- Cumulative oil, gas and water production to June 2015. Field by field production data is available in the public domain (WAPIMS) up to 2015 but not available on a field-by-field basis post 2015.
- Well completion reports.
- Well test interpretations.
- Petrophysical analysis, and
- Western Australia Atlas of Petroleum Fields Onshore Perth Basin[15].

The initial review aimed to identify the fields which appeared to be promising hydrogen storage candidates and those which were not suitable. Production history was used to estimate storage capacity of fields against what RISC estimates the WA hydrogen storage requirements to be. In some cases, produced volumes were deemed insufficient for hydrogen storage and the field was therefore deemed not suitable

[15] OWAD-JONES, D.L., and ELLIS, G.K., 2000, Western Australia atlas of petroleum fields, Onshore Perth Basin: Petroleum Division, DMEWA. Volume 1.

for further investigation. For example, the Evandra oil field which produced 1,900 bbl of liquid in total is not deemed suitable.

For the calculation of the theoretical hydrogen storage capacity in each gas field, RISC has taken the total natural gas production volume as an approximate estimate. For the oil fields, the total oil production at standard conditions was converted to an approximate reservoir volume using oil formation volume factors, and this volume was converted to a hydrogen volume at standard conditions using gas formation volume factors.

These produced hydrocarbon volumes are considered the maximum hydrogen storage volume without re-filling the field to a greater extent than originally filled by hydrocarbons. A safety margin may have to be applied to ensure that hydrogen and/or hydrocarbons are not pushed below the original hydrocarbon water contact and confirmed trap. The degree of refill must also consider the maximum allowable pressure without fracturing the caprock. RISC also notes that the stated volumes are the total available volume, part of which may have to be used for cushion gas.

For some fields, additional production occurred post-2015. However, this production data is not publicly available so the known production up to 2015 may be conservative.

RISC also considered permeability and net reservoir thickness to be important reservoir properties for the evaluation of hydrogen storage potential. High permeability and net thickness will enable higher injection and withdrawal rates.

Fields where further appraisal or development activities is planned, such as Walyering field, were considered not suitable for storage modelling as it is unclear when the field depletion will conclude and it will become available for potential storage. The Jingemia field was also considered not suitable as an exploration well is planned on the license in the near future, with one of the reservoir targets being main producing reservoir in Jingemia field.

RISC has not considered commercial aspects, other than that highlighted below for the Tubridgi and Mondarra fields, access or title for its assessment and ranking of the fields. RISC also notes that at present there is currently no legislation to govern underground storage, including hydrogen, in WA.

Following its assessment of the fields, RISC has ranked the fields for hydrogen storage potential. The ranking criteria were field availability, field productivity/injectivity and storage capacity. All depleted Perth Basin fields are well located with respect to the potential hydrogen production projects.

- The Mondarra and Tubridgi fields are technically very strong storage candidates. However, their ranking have been downgraded due to the existing natural gas storage projects in place in these fields, thereby impacting their short-term availability. RISC notes that in time, this situation may change.
- The Dongara field is the largest field evaluated by RISC with approximately 458 Bcf of gas produced. Such large hydrogen storage volumes are not forecast in the short to medium term so this field would not be an ideal short to medium-term candidate. RISC estimate pure hydrogen storage demand to be between 1 and 10 Bcf (refer Section 6). Therefore, the Dongara field ranking has been downgraded. However, RISC notes that this situation may change in the longer term.
- Oil fields have also been downgraded due to the added complexity and issues of hydrogen storage in oil fields as compared to natural gas fields.

RISC's field ranking is shown in Table 7-1. Further information on the identified candidates is detailed in sections 7.1.1 to 7.1.13, and in the Appendices.

Table 7-1: West Australia depleted oil and gas fields; ranked for hydrogen storage potential

Field	Basin	Storage (Bcf)	H2 Storage Potential	Ranking	Reasoning/Risks
Xyris gas field	Perth	9.3	Strong	1	Good storage capacity, high quality reservoir
Yardarino gas field	Perth	5.1	Strong	2	Good storage capacity, high quality reservoir - less production than Xyris so lower storage potential
Beharra Springs gas field	Perth	89.0	Strong	3	Good storage capacity, high quality reservoir. Beharra Springs Deep under development
Red Back gas field	Perth	22.0	Strong	4	Good storage capacity, high quality reservoir. Beharra Springs Deep under development
Tarantula gas field	Perth	19.0	Strong	5	Good storage capacity, permeability low at 10-20mD
Tubridgi gas field	Carnarvon	69.0	Strong	6	Good storage capacity. Currently used as natural gas storage facility (not currently available). Reasonable productivity
Mondarra gas field	Perth	23.9	Strong	7	Good storage capacity. Currently used as natural gas storage facility (not currently available). High productivity
Dongara gas field	Perth	458.0	Moderate	8	Very high storage capacity, potentially too large for H2 requirements. Good reservoir properties. Many (47) wells
Red Gully gas field	Perth	4.0	Moderate	9	Good storage capacity, high quality reservoir, wells watered out
Apium gas field	Perth	1.2	Moderate	10	Sufficient gas production - permeability is very low (<5mD), reducing potential injection and withdrawal rates
Gingin gas field	Perth	1.7	Moderate	11	Sufficient gas production - varying properties across field, poor deliverability in production wells
Hovea oil field	Perth	3.4	Moderate	12	Good storage capacity, high permeability - risk of potential H2 dissolution and contamination in/from oil
Mt Horner oil field	Perth	1.0	Moderate	13	Limited storage capacity, high water saturation, - risk of potential H2 dissolution and contamination in/from oil
Corybas gas field	Perth	0.8	No	N/A	Low reservoir productivity (hydraulically fractured wells)
Eremia gas field	Perth		No	N/A	In communication with Hovea (Hovea a stronger candidate)
Evandra oil field	Perth	minor	No	N/A	Produced volume too low (only 1900 bbl of oil + water produced)
Gingin West gas field	Perth	minor	No	N/A	Only 0.3 Bcf produced, in communication with Gingin which is a stronger candidate
Walyering gas field	Perth	0.3	No	N/A	Limited storage capacity. Appraisal well to be drilled by Stike Energy/Talon in CY21
Woodada gas field	Perth	52.9	No	N/A	Limited patchy permeability (<5mD) fractured carbonate. Some gas in tight zones. 14 of 17 wells.
Xyris South gas field	Perth		No	N/A	In communication with Xyris which is considered a stronger candidate
Jingemia oil field	Perth		No	N/A	Cervantes-1 to be drilled in CY21 on the permit. Dongara Sandstone could be in communication
North Yardanogo oil field	Perth	minor	No	N/A	Well encountered only 1m of pay with water cut rapidly increasing to 90% during DST.
Rough Range oil field	Carnarvon	minor	No	N/A	Only 0.3 MMbbl of oil+water produced, water cut 96% at EOFL.

7.1.1. Hovea oil field

Hydrogen storage potential: **Moderate**

7.1.1.1. Summary

The Hovea oil field is located in the L 1 permit in the Perth Basin. It produced 7.4 MMstb of oil from the Dongara sandstone from late 2002 to 2006 before being shut-in. The estimated STOIIP was 10 to 15 MMstb, giving a final oil recovery factor of approximately 50%. The Dongara sandstone at Hovea was estimated to be 50 m thick with a net to gross ratio of 90%. The average permeability was 600 mD. Many years of production from the depleted Dongara gas field 5 km to the north left the Hovea field depleted from the original reservoir pressure by approximately 750 psi, suggesting the fields are hydraulically connected. Significant water production shows a high degree of aquifer influx and pressure support.

7.1.1.2. Positives for hydrogen storage

Significant production has occurred from the field, leaving sufficient voidage for a storage project. Based on the reported oil production, a theoretical total hydrogen storage capacity of 3.4 Bcf is calculated, as summarised in Table 7-2.

Table 7-2: Hovea Field production summary and hydrogen storage potential

Fluid	Volume
Water production (MMstb)	33.5
Oil production (MMstb)	7.4
Oil production (MMrbbl)	8.1
Reservoir volume (Brcf)	0.1
Approximate hydrogen storage capacity (Bcf)	3.4

Hydrogen injection and production rates would be high due to the good reservoir permeability, high net to gross and reasonable net pay thickness. RISC notes that majority of the existing wells have been plugged and abandoned (P&A), with the remaining wells suspended. The suspended wells could potentially be used for hydrogen injection and production.

7.1.1.3. Negatives for hydrogen storage

The estimated oil recovery factor from the Hovea field was approximately 50%, leaving a large volume of oil in the field. This could lead to contamination of injected hydrogen. Also hydrogen losses may occur through dissolution of hydrogen in oil.

There is evidence of connection between the Hovea and Dongara fields, with 750 psi in depletion observed. This could lead to the loss of injected hydrogen, with the gas being more mobile than oil or hydrocarbon gas. However, the depletion is most likely the result of pressure communication through a regional aquifer, which would remove the risk of gas flowing to other reservoirs.

7.1.2. Mondarra gas field

Hydrogen storage potential: **Strong**

7.1.2.1. Summary

The Mondarra gas field is located in the L 1 license in the Perth Basin. It produced 24 Bcf of gas and 0.06 MMstb of condensate from the Dongara sandstone from 1972 to 1994 before being shut-in. The field is classified as depleted. The Mondarra field contains two structures, Mondarra 1 and Mondarra 2. The original gas in place estimate for the Mondarra 1 structure is 25.7 Bcf with gas production of 22.3 Bcf. Production from the Mondarra 2 structure is 1.6 Bcf, however gas original in place estimates are not available. Permeability in the Mondarra 1 structure is 127mD with a gross pay interval of 40m and a NTG of 85%.

7.1.2.2. Positives for hydrogen storage

Based on the reported gas production, a theoretical total hydrogen storage capacity of 24 Bcf is calculated, as summarised in Table 7-3.

Table 7-3: Mondarra Field production summary and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.06
Water production (MMstb)	0.06
Gas production (Bcf)	23.9
Approximate hydrogen storage capacity (Bcf)	23.9

Mondarra is currently operated as a gas storage facility by APA Group, with three wells utilised as both injectors and producers. As per APA publications, the natural gas storage capacity is 15 PJ, with injection and withdrawal capabilities of 70 TJ/d and 150 TJ/d respectively. Existing wells and infrastructure currently used to inject and withdraw natural gas could be used for hydrogen injection and withdrawal.

7.1.2.3. Negatives for hydrogen storage

Mondarra has been proven as a natural gas storage facility, RISC therefore considers the field a very strong candidate for hydrogen storage. The main concern is that the field is currently being used for gas storage in the Parmelia gas pipeline. There would have to be a strong business case to convert the storage to pure hydrogen.

Gas samples from the Mondarra-1 drill stem test indicated 4.1% CO_2. Stored sales specification gas is likely to have reduced the CO_2 content. However, residual gas in the reservoir may contain a similar concentration of CO_2. Hydrogen will react with CO_2 to form methane, resulting in some loss of the injected hydrogen.

7.1.3. Beharra Springs gas field

Hydrogen storage potential: **Strong**

7.1.3.1. Summary

The Beharra Springs gas field is located in the L 11 license in the Perth Basin. It has been developed through the 25 TJ/d Beharra Springs gas plant with adjacent gas fields Redback and Tarantula. It produced 89 Bcf of gas and 0.2 MMstb of condensate from the Wagina Sandstone from 1992 to 2015. Further production has occurred since 2015 but declined to minor current levels. Four wells have been drilled and completed on the Wagina Sandstone. Beharra Springs 3 tested gas at 26 MMscf/d with an estimated maximum flow potential (AOF) of 100 MMscf/d and 500 mD permeability. Beharra Springs 1 and 2 tested gas at 78 and 67 MMscf/d.

Gas was discovered in the Kingia Formation of the Beharra Springs Deep well in 2019 and this is planned to be developed through the Beharra Springs gas plant.

7.1.3.2. Positives for hydrogen storage

Good hydrogen storage capacity consistent with estimated storage needs. Based on the reported gas production, a theoretical total hydrogen storage capacity of 89 Bcf is calculated, as summarised in Table 7-4.

Table 7-4: Beharra Springs Field production history to June 2015 and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.2 up to 2015
Water production (MMstb)	0.6 up to 2015
Gas production (Bcf)	89 up to 2015
Approximate hydrogen storage capacity (Bcf)	89

The Wagina Formation was divided into an upper and lower zone which are in hydraulic communication with a common GWC[16]. The upper zone has 10 to 11% porosity in wells 1, 2 and 3 and the lower zone 4 to 6% porosity. Better reservoir in the upper zone may assist keeping injected hydrogen at the crest of the field. Some aquifer influx and water production is expected.

High gas rates were historically achieved, indicating good injection and production capacity for hydrogen storage. RISC therefore considers Beharra Springs Wagina reservoir a strong candidate for the modelling stage. It may be possible to use some of the existing production wells although a new processing facility would be required.

7.1.3.3. Negatives for hydrogen storage

In this limited review, no issues have been identified in using Beharra Springs for hydrogen storage. The size of the field may be larger than required that can result in increased hydrogen losses and increased contamination with remaining hydrocarbon gas

7.1.4. Redback gas field

Hydrogen storage potential: **Strong**

7.1.4.1. Summary

The Redback gas field is located in the L 11 license in the Perth Basin. It has been developed through the 25 TJ/d Beharra Springs gas plant with adjacent gas fields Beharra Springs and Tarantula. It produced 22 Bcf of gas and negligible condensate from the Wagina Sandstone from 1992 to 2015 with a maximum monthly

[16] EP320 Beharra Springs Fields Simulation Study (July 1993)

rate of 15 MMscf/d from 2 wells. Further production has occurred since 2015 but declined to minor current levels.

Two well have been drilled and completed on the Wagina Sandstone. Redback-1 was plugged and suspended without testing and interpreted as tight with less than 5% porosity with some fracturing at the top. Redback-2 found 14.3m net pay in the Wagina Sandstone and tested at 5.3 MMscf/d and subsequently used for production.

Redback South-1 tested a second gas accumulation in 2010 at 38 MMscf/d and has subsequently been used for production. The upper interval is interpreted with 3.3 m net pay, 13.8% porosity, 42% water saturation and 237 mD permeability. Additional poorer quality pay in a lower section is also interpreted.

7.1.4.2. Positives for hydrogen storage

Good hydrogen storage capacity consistent with estimated storage needs. Based on the reported gas production, a theoretical total hydrogen storage capacity of 22 Bcf is calculated, as summarised in Table 7-6. This is the combined Redback-2 and Redback South-1 production.

Table 7-5: Redback Field production history to June 2015 and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.01 up to 2015
Water production (MMstb)	0.1 up to 2015
Gas production (Bcf)	22 up to 2015
Approximate hydrogen storage capacity (Bcf)	22

The Wagina Formation was divided into a better-quality upper zone and lower quality lower zone which are in hydraulic communication with a common GWC. The better reservoir in the upper zone may assist keeping injected hydrogen at the crest of the field.

High gas rates have been measured in Redback South, indicating good injection and production capacity for hydrogen storage. RISC therefore considers the Redback South reservoir a strong candidate for the modelling stage. It may be possible to use the existing production well although a new processing facility would be required.

7.1.4.3. Negatives for hydrogen storage

In this limited review, no issues have been identified in using Redback South for hydrogen storage. The lower well test flowrate in Redback-2 make it less attractive than Redback South.

7.1.5. Tarantula gas field

Hydrogen storage potential: **Strong**

7.1.5.1. Summary

The Tarantula gas field is located in the L 11 license in the Perth Basin. It produced 12.7 Bcf of gas and 0.03 MMstb of condensate from the Wagina Sandstone from 2005 to 2015. Post 2015 is estimated to have increased the cumulative gas production by 50% to approximately 19 Bcf. The Tarantula-1 ST1 well was perforated in upper and lower sections of the Wagina Sandstone. The lower sandstone has a net pay thickness of 11 mMD, permeability of 17.6 mD and an NTG of 51%. The top of the lower sandstone is approximately 22m below the base of the upper sandstone. Production tests concluded that virtually all production originated from the lower sandstone.

7.1.5.2. *Positives for hydrogen storage*

Good hydrogen storage capacity consisted with estimated storage needs. Based on the reported gas production, a theoretical total hydrogen storage capacity of 19 Bcf is calculated, as summarised in Table 7-6.

Table 7-6: Tarantula Field production history to June 2015 and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.03 up to 2015
Water production (MMstb)	0.07 up to 2015
Gas production (Bcf)	19 (12.7 up to 2015)
Approximate hydrogen storage capacity (Bcf)	19

Although the permeability is relatively low at 17.6 mD compared to some other Perth Basin fields, Tarantula-1 ST1 was production tested at 35 MMscf/d indicating that high gas rates were historically achieved. RISC therefore considers Tarantula a strong candidate for the modelling stage.

7.1.5.3. *Negatives for hydrogen storage*

RISC considers there is uncertainty on communication between the upper and lower sandstones of the Wagina. Petrophysical interpretation concluded reservoir properties are better in the lower sandstone and that it was the source of the majority of production. If there is communication between the zones, there is risk that hydrogen injected in the lower sandstone could migrate upwards to the upper sandstone. The net pay thickness and permeability of the upper sandstone (2.7 mMD and 0.58 mD) render this zone a poor hydrogen storage candidate. The permeability of 17.6 mD in the lower sandstone is also low when compared to some other Perth Basin candidates, although not of significant concern.

RISC considers there may be some uncertainty in the petrophysical interpretation of net sand and net pay. The net pay thickness and permeability are higher than the net sand. Whilst this does not disqualify Tarantula as a potential hydrogen storage candidate, if this field progresses to the modelling stage this should be reviewed to confirm stated reservoir properties.

7.1.6. Tubridgi gas field

Hydrogen storage potential: **Strong**

7.1.6.1. *Summary*

The Tubridgi gas field is located in the L 9 license in the Carnarvon Basin. The field produced 69 Bcf of gas from 1991 to 2005 with no condensate production noted. RISC notes that limited reservoir properties data are available in the public domain.

7.1.6.2. *Positives for hydrogen storage*

Significant production has occurred from the field, leaving good voidage for a storage project. Based on the gas production, a theoretical total hydrogen storage capacity of 69 Bcf is calculated, as summarised in Table 7-7.

Table 7-7: Tubridgi Field production history and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.0
Water production (MMstb)	1.7
Gas production (Bcf)	69.0
Approximate hydrogen storage capacity (Bcf)	69.0

The Tubridgi gas field has been proven as a natural gas storage facility, RISC therefore considers the field a strong candidate for hydrogen storage. The current operator, Australia Gas Infrastructure Group, claims field storage capacity of 52 PJ, or approximately 50 Bcf. Injection and withdrawal capacities are stated as 90 TJ/d and 60 TJ/d respectively. Existing wells and surface infrastructure could potentially be used for hydrogen. The field is also located in the Carnarvon Basin, offering a storage site for green hydrogen produced in the surrounding area.

It is likely that the existing wells and facilities could be used for hydrogen storage.

7.1.6.3. Negatives for hydrogen storage

As is the case with Mondarra, the current use of Tubridgi as a natural gas storage site is the main concern. The length of agreement/s in place between the operator and its' customers and contractual terms and conditions are unknown to RISC. A strong business case would be required to stop natural gas storage and convert the field to pure hydrogen storage.

7.1.7. Xyris gas field

Hydrogen storage potential: **Strong**

7.1.7.1. Summary

The Xyris gas field is located in the L 1 license in the Perth Basin. It produced 9.3 Bcf of gas from the Dongara Sandstone from 2004 to 2010 with an initial monthly rate of 9.7 MMscf/d from 1 well. Production in the field is from a single well, Xyris-1, which was drilled due to success in the Dongara Sandstone at the nearby Hovea, Mondarra and Dongara fields. The well completion report ('WCR') concluded that the Dongara Sandstone may be under-pressured at Xyris-1 due to production in the nearby Hovea oil field. Log analysis indicated a 69 mD.m gross intersection with 21 mD.m of net pay. Average porosity is 11% and water saturation 18%. The WCR noted core derived permeabilities at the nearby Hovea-3 were 123-2078mD. Given the conclusion that Xyris was partially depleted due to Hovea production, permeability at Xyris is assumed to be high and comparable with the Hovea field.

Xyris South-1 was drilled in the Xyris South field, with well test interpretation indicating this well was in communication with Xyris-1. Production from Xyris South is minor (0.2 Bcf) and communication between these fields is not considered to be a risk for hydrogen storage.

7.1.7.2. Positives for hydrogen storage

The field has a good storage capacity consistent with estimated hydrogen storage requirements. Based on the reported gas production, a theoretical total hydrogen storage capacity of 9 Bcf is calculated, as summarised in Table 7-8.

Table 7-8: Xyris Field production history and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.02
Water production (MMstb)	0.03
Gas production (Bcf)	9.3
Approximate hydrogen storage capacity (Bcf)	9.3

The Xyris field produced a high volume of gas with minor condensate and water production. Although Xyris was interpreted to be in communication with the Hovea oil field, Xyris provides a potential hydrogen storage site in a gas bearing zone of the Dongara Sandstone. The high permeability will allow for high injection and withdrawal rates.

The Xyris gas plant is currently being used for initial production from Waitsia gas field. Once the Waitsia gas plant is completed, the Xyris plant may potentially become available for hydrogen operations.

7.1.7.3. Negatives for hydrogen storage

The Xyris-1 well has been P&A'd as per the WAPIMS database. If the Xyris field was pursued as a storage field, new well/s would be required

7.1.8. Yardarino gas field

Hydrogen storage potential: **Strong**

7.1.8.1. Summary

The Yardarino gas field is located in the L 2 license in the Perth Basin. The field produced 5 Bcf of gas from 1978 to shut-in in 2010 with negligible condensate production and a maximum monthly gas rate of 6.7 MMscf/d. The primary field target was the Dongara Sandstone. Yardarino-1 intersected 19.5 m of gross pay, with 4 m net of oil and 14 m of net gas pay. Average porosity and water saturation in the gas bearing zone is 13% and 25% respectively. The field has high permeability at 120 mD. The GIIP was estimated at 15 Bcf, suggesting a gas recovery factor of 33%.

7.1.8.2. Positives for hydrogen storage

The field has a good storage capacity consistent with estimated hydrogen storage requirements. Based on the reported gas production, a theoretical total hydrogen storage capacity of 5 Bcf is calculated, as summarised in Table 7-9.

Table 7-9: Yardarino Field production history and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.005
Water production (MMstb)	0.6
Gas production (Bcf)	5.1
Approximate hydrogen storage capacity (Bcf)	5.1

The high permeability in the Yardarino field will allow for high injection and withdrawal rates.

7.1.8.3. Negatives for hydrogen storage

Although there is uncertainty on GIIP estimations, recovery factor is estimated at 33% and therefore there is potential for a significant volume of unproduced natural gas remaining in the reservoir. Given the high permeability of the field, the low recovery factor for the pressure depletion/minor water drive reservoir is surprising and warrant further investigation. Whether the GIIP is overstated (and therefore recovery factor is actually higher), or water has influxed and stopped gas production, both present risks for hydrogen storage. High volumes of remaining gas present the risk of hydrogen contamination with methane and if water has influxed a larger cushion gas volume may be required.

All wells in the Yardarino field (including Central and North Yardarino) are P&A as per WAPIMS, therefore new wells will need to be drilled if the field is pursued for hydrogen storage. This is not of significant concern and does not disqualify Yardarino as a potential candidate for modelling.

7.1.9. Apium gas field

Hydrogen storage potential: **Moderate**

7.1.9.1. Summary

The Apium gas field is located in the L 1 license of the Perth Basin. The field produced 1.2 Bcf with negligible condensate from the Dongara sandstone between 2007 and 2012, with a maximum gas rate from 1 well of 2.4 MMscf/d. Interpretation of the Apium-1 well test concluded low permeability, estimated at 4.5 mD. The GIIP was estimated from P/Z at 2.6 – 3.3 Bcf from the well test, however there is uncertainty on this value due to the limited production data available at the time. Volumetric calculations based on the model used in the well test analysis suggested GIIP of 3.4 Bcf, supporting the material balance estimates. The final pressure was 13 psi below initial suggesting a closed system.

7.1.9.2. Positives for hydrogen storage

The field has a good storage capacity consistent with estimated hydrogen storage requirements. Based on the reported gas production, a theoretical total hydrogen storage capacity of 1 Bcf is calculated, as summarised in Table 7-10.

Table 7-10: Apium Field production history and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.002
Water production (MMstb)	0.01
Gas production (Bcf)	1.2
Approximate hydrogen storage capacity (Bcf)	1.2

The first Apium well was drilled in 2004, with subsequent well in 2007. Apium North-1 was drilled with gas shows in 2009 but a P&A'd. Apium-1 and 2 are relatively new wells compared to some of the wells drilled at other fields in the Perth Basin (i.e. 1960's) and have not been abandoned. They may be useable for hydrogen injection and withdrawal.

7.1.9.3. Negatives for hydrogen storage

RISC considers the main concern for hydrogen storage in the Apium field to be the low permeability, estimated at 4.5 mD at Apium-1. The low permeability will significantly reduce both potential injection and withdrawal rates. With other fields in the Perth Basin having significantly higher permeability and productivity, Apium is less attractive than other candidates for hydrogen storage modelling.

7.1.10. Gingin gas field

Hydrogen storage potential: **Low**

7.1.10.1. Summary

The Gingin gas field is located in the EP 389 permit and L 18 and L 19 licenses in the Perth Basin. The field produced 1.7 Bcf of gas with minor condensate production from 1972 to 1976 with a maximum monthly rate of 6.4 MMscf/d. The target formation was the Cattamarra Coal Measures. Significant variation in reservoir properties were noted across the field.

- Gingin-1 well with an average permeability of 70 mD produced 1.7 Bcf. Gingin-1 was deemed to be located in a small, isolated fault block likely bounded by thick shales.
- Gingin-2 well is estimated to have poor permeability (2 mD) and the flowrate during a 14-day production testing dropped from 3 to 0.5 MMscf/d.

The total field is estimated to have 477 Bcf GIIP but poor permeability and compartmentalization have limited production.

7.1.10.2. Positives for hydrogen storage

Gingin-1 has a good storage capacity consistent with estimated hydrogen storage requirements. Based on the reported gas production, a theoretical total hydrogen storage capacity of 2 Bcf is calculated, as summarised in Table 7-11.

Table 7-11: Gingin Field production history and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.02
Water production (MMstb)	0.02
Gas production (Bcf)	1.7
Approximate hydrogen storage capacity (Bcf)	1.7

Well completion reports indicate Gingin-1 is located in a small, isolated fault block. Given the permeability at Gingin-1 was relatively high (70 mD), initial screening identified the Gingin field as a potential candidate for hydrogen storage.

7.1.10.3. Negatives for hydrogen storage

Although the Gingin field produced 1.7 Bcf, long term production tests from Gingin-1 noted low deliverability. The first Gingin-1 production test commenced in March 1972, with production lasting only until December 1972[15]. Whilst Gingin-1 is isolated in a fault bounded block and estimated to have relatively high permeability at 70 mD, the poor deliverability is of concern for hydrogen storage as withdrawal rates may be low. The Gingin field therefore has moderate to low potential for hydrogen storage.

7.1.11. Red Gully gas field

Hydrogen storage potential: **Moderate**

7.1.11.1. Summary

The Red Gully gas field is located in EP 389 permit and L 18 and L 19 licenses in the Perth Basin. The field produced 4 Bcf of gas and 0.2 MMstb of condensate from mid 2013 to June 2015 with minor water production. Petrophysical interpretation of Red Gully-1 indicated net pay average porosity of 13%, permeability of 4.5 mD and water saturation of 48%. Petrophysical interpretation of Red Gully North-1 noted lower porosity at 11%, higher permeability at 23 mD and higher water saturation at 54%.

7.1.11.2. Positives for hydrogen storage

The field has a good storage capacity consistent with the estimated hydrogen storage requirements. Based on the reported gas production to end-2015, a theoretical total hydrogen storage capacity of 4 Bcf is calculated, as summarised in Table 7-12.

Table 7-12: Red Gully Field production history to June 2015 and hydrogen storage potential

Fluid	Volume
Condensate production (MMstb)	0.20
Water production (MMstb)	0.01
Gas production (Bcf)	4.01
Approximate hydrogen storage capacity (Bcf)	4.0

The average production rate from well Red Gully-1 in 2013-2015 is reasonable at 5 MMscf/d. RISC notes that we do not have access to production data for this field post June 2015.

7.1.11.3. Negatives for hydrogen storage

RISC is unaware of issue with Red Gully as a hydrogen storage field. The limited permeability may limit injection and re-production rates,

7.1.12. Mount Horner oil field

Hydrogen storage potential: **Moderate**

7.1.12.1. Summary

The Mount Horner oil field is located in the L 7 license in the Perth Basin. The field produced 1.9 MMstb of oil and 20.6 MMstb of water from 1984 to 2011, with no gas production recorded. The primary targets were the Cattamarra Coal Measures and Irwin River Coal Measures. The “F Sand” is located in the Cattamarra Coal Measures, with average porosity of 20%, permeability of 86-380 mD and water saturation of 60-70%. Production ceased in 2011 due to high water cut and aged infrastructure.

7.1.12.2. Positives for hydrogen storage

The oil production converts to a potential hydrogen storage volume of 1 Bcf (Table 7-13), which is a good storage capacity consistent with estimated hydrogen storage requirements.

Table 7-13: Mount Horner Field production history and hydrogen storage potential

Fluid	Volume
Water production (MMstb)	20.6
Oil production (MMstb)	1.9
Oil production (MMrbbl)	2.0
Reservoir volume (Brcf)	0.01
Approximate hydrogen storage capacity (Bcf)	1.0

The high reservoir permeability will allow for high injection and withdrawal rates.

7.1.12.3. Negatives for hydrogen storage

Water saturation in the F sand of the Cattamarra Coal Measures was 60-70%. There has been significant water production from the field, with water contributing 92% of total liquids production, the field was also shut-in due to high water cut. Therefore, water production is a risk during hydrogen storage and a cushion gas volume may be required to avoid this.

RISC considers the storage of pure hydrogen in oil fields to be higher risk than gas fields. There is potential for the dissolution and/or reaction of hydrogen with oil.

7.1.13. Dongara gas field

Hydrogen storage potential: **Moderate**

7.1.13.1. Summary

The wells within the Dongara field are located in the L 1 and L 2, licenses in the Perth Basin. The field has produced 458 Bcf of gas from 1972 to 2015, significantly higher than the other gas fields reviewed in this report. The main reservoir of the field is the Dongara Sandstone. Reservoir parameters vary greatly in the field, with permeability of 26 mD at Dongara-25 to 2744 mD in Dongara-27. The average permeability is estimated at 230 mD. Average porosity and water saturation in the gas column is 21% and 15% respectively. The GIIP of the Dongara field was estimated at 540 Bcf, suggesting a recovery factor of 85%.

7.1.13.2. Positives for hydrogen storage

The field has a high storage capacity significantly higher than the WA estimated hydrogen storage requirements considered as part of this report. Based on the reported gas production, a theoretical total hydrogen storage capacity of 458 Bcf is calculated, as summarised in Table 7-14.

Table 7-14: Dongara Field production history to June 2015 and hydrogen storage potential

Fluid	Volume
Oil production (MMstb)	1.5
Water production (MMstb)	2.2
Gas production (Bcf)	457.7
Approximate hydrogen storage capacity (Bcf)	457.7

The permeability in the Dongara field is high, allowing for high injection and withdrawal rates. RISC notes that we do not have access to production data for this field post June 2015.

7.1.13.3. Negatives for hydrogen storage

The Dongara gas field is very large (in terms of gas produced and GIIP estimates) compared to the other fields reviewed within this report. The field is currently depleted and given its significant size a large cushion gas volume may be required.

Including side-tracks, there has been 47 wells drilled in total across the field, with 31 of these wells being drilled prior to 1991 (i.e. 30 years old). The integrity of these old wells for injection and withdrawal may be questionable and is a risk if the field is pursued as a storage candidate. Furthermore, the greatly varying reservoir properties (e.g. permeability of 26 mD and 2744 mD) seen across the field suggests modelling will be a more intensive process compared to the smaller Perth Basin fields. Considering only reservoir properties, the Dongara field is an attractive candidate for hydrogen storage, however RISC considers there are risks associated with its size and the age of some wells.

7.2. Salt

Evaporites (salt) of Ordovician and Silurian age are identified in the Canning, Southern Carnarvon and Northern Carnarvon Basins[17] of WA (Figure 7-2). In addition, salt of Precambrian age has been identified in the Southern Canning, Officer and Amadeus Basins[18].

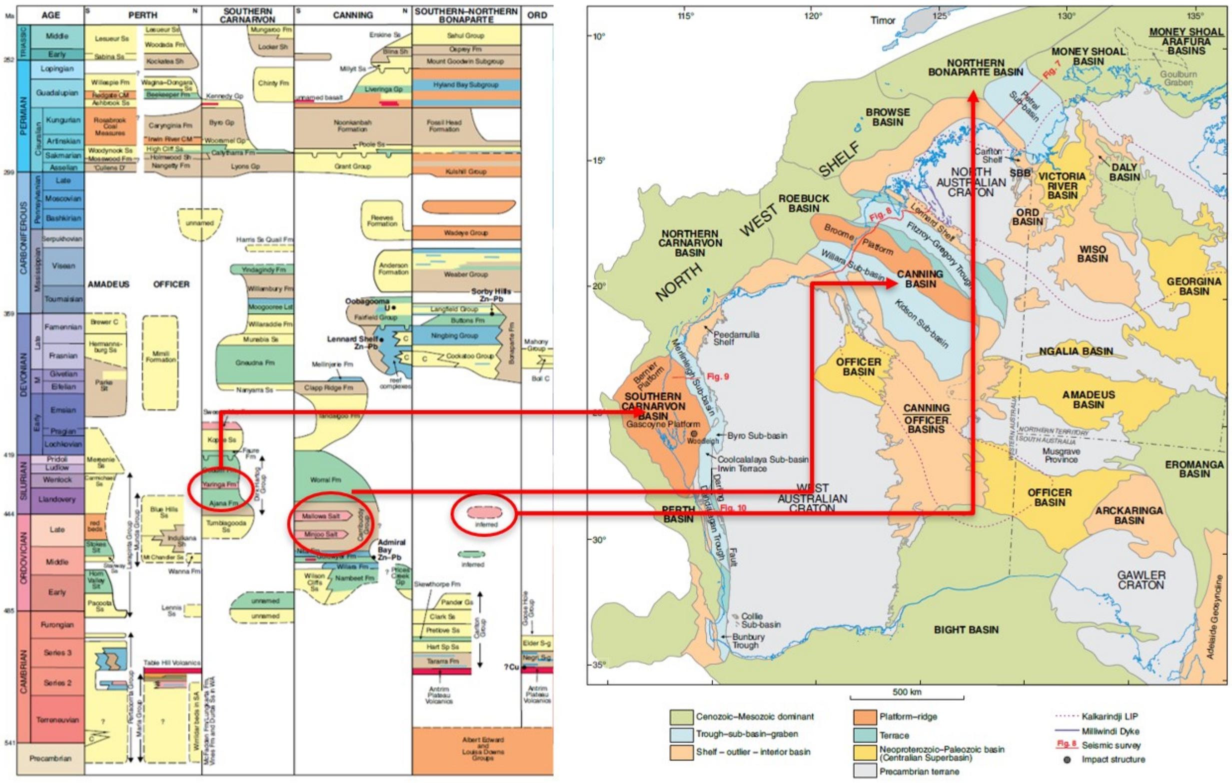

Figure 7-2: Evaporites in WA[17]

[17] A Paleozoic perspective of Western Australia, A.J. Mory, 2017.
[18] Possible Major Diapric Structures in the Southern Canning and Northern Officer Basins, J. Craig et al.

The salt deposits in Canning Basin are the most significant, where evaporites are formed within arid red-bed successions in the Carribuddy Group (Mallowa and Minjoo). Mapping by Haines[19] (Figure 7-3) shows that locally the Mallowa salt is up to 800 m thick and is the most voluminous evaporite formation known in Australia.

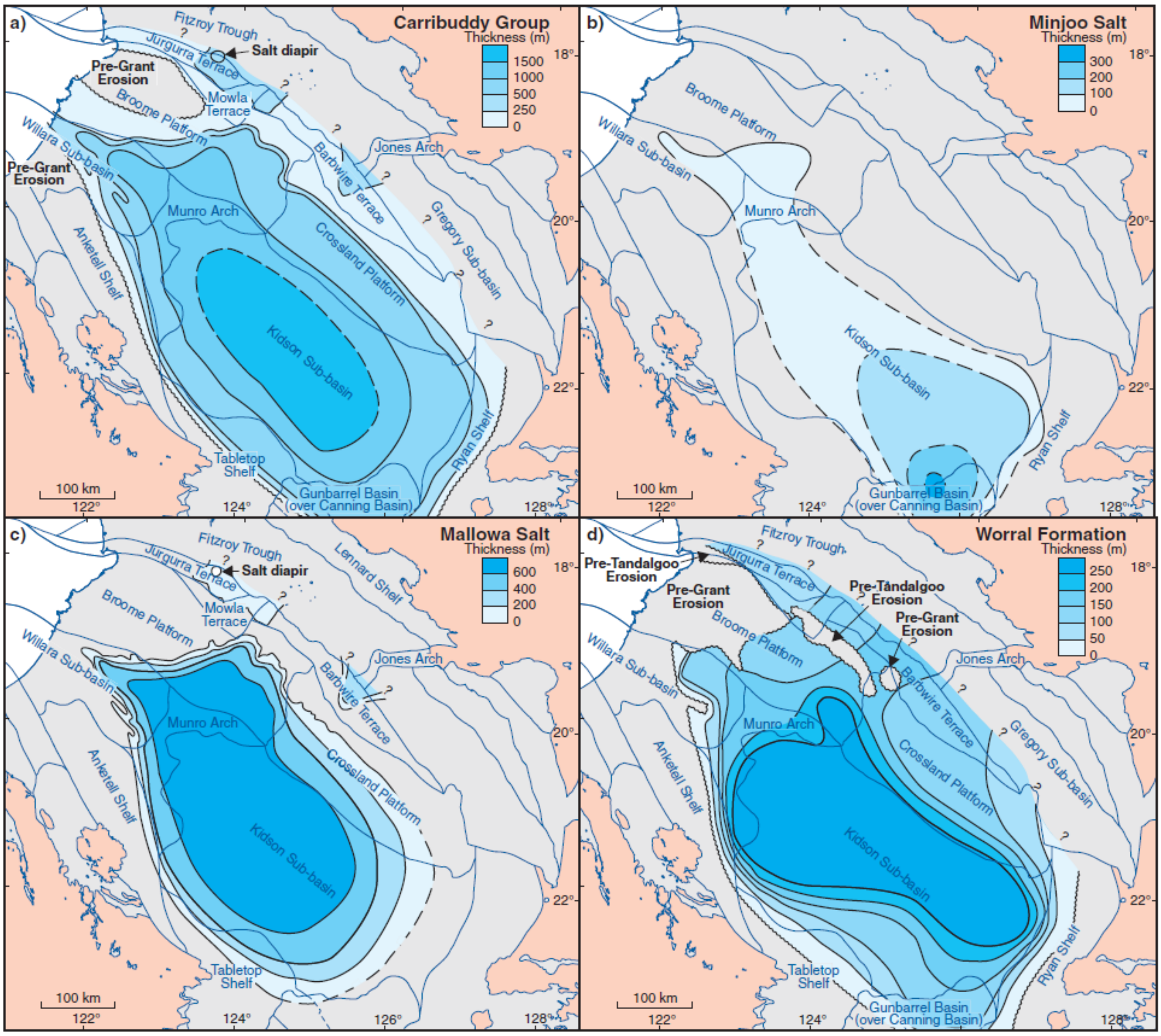

Figure 7-3: Isopach maps for a) Carribuddy Group, b) Minjoo Salt, c) Mallowa Salt and d) Worral Formation [19]

The thickest sequence of salt was encountered in Frome Rocks-1 well (Figure 7-4), located 150 km east of Broome, 100 km south of Derby and about 300 km to the north-east of the proposed Asian Renewable Energy Hub. The age and prevenance of the salt is poorly constrained.

[19] The Carribuddy Group and Worral Formation, Canning Basin WA: Reassessment of the stratigraphy and petroleum potential, P.W.Haines, 2010.

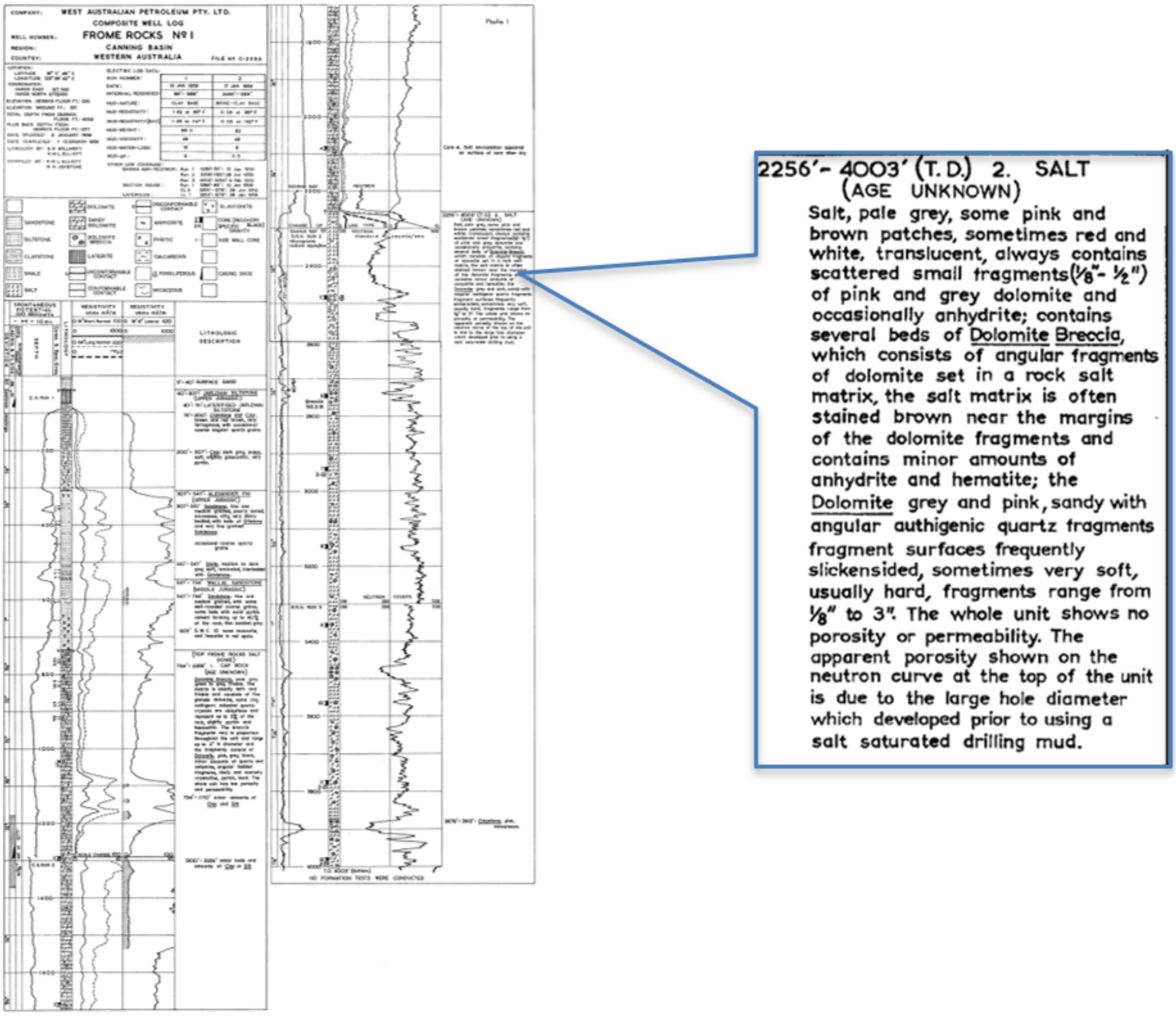

Figure 7-4: Frome Rocks-1 composite log extract

The evaporites in the Southern Carnarvon Basin are formed within the shallow-marine carbonate facies of the Dirk Hartog Group (Silurian Yaringa Formation) and are thinner (up to 105 m) as shown in Figure 7-5. The evaporates in the Northern Bonaparte Basin are known only from salt structures imaged on seismic reflection profiles and in wells drilled into salt domes. They are likely to be older than Late Devonian.

Pure salt, or halite, is ideal for hydrogen storage. Halite appears to be the media for the known salt related storage sites. Halite is mobile in the subsurface and can express at the surface making it attractive as a storage solution (depth of burial).

Evaporites are typically mixed lithologies with interbedded salt rich layers. The depth of burial and interbedded lithologies may make them unsuitable or less favourable to create salt caverns for hydrogen storage. The characteristics of the WA's evaporites are not the scope of this study and further analysis is required.

GSWA is currently undertaking a project to characterize subsurface salt in WA and map their distribution which will help inform their potential for salt cavern creation.

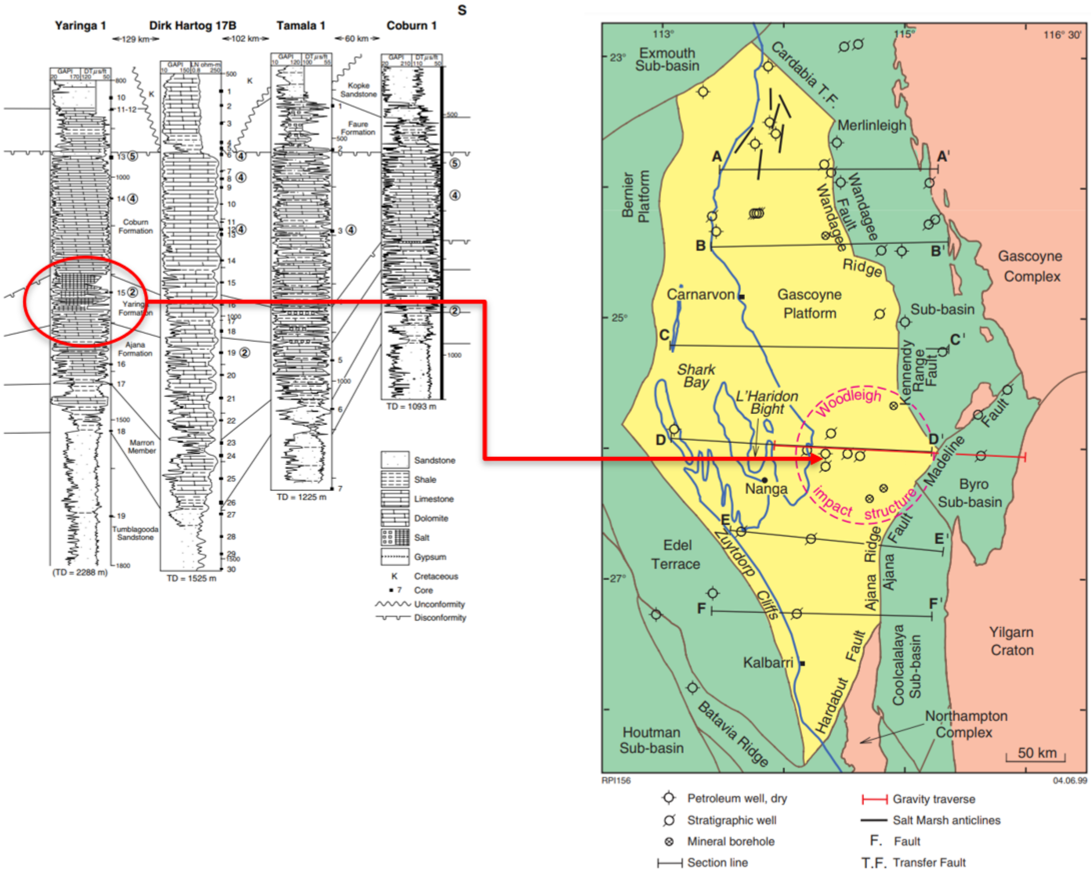

Figure 7-5: Evaporites in the Southern Carnarvon Basin

Salt caverns for hydrogen storage must be created by circulating (pumping) low salinity water into the salt. This dissolves the salt returning high salinity brine. A suitable water source and disposal of the high salinity brine is required.

The water supply does not have to be fresh water, but lower salinity water is more effective at creating caverns. The maximum solubility of salt in water is approximately 380 grams per kg, compared to seawater that has approximately 3.5g per kg. of water.

Salt has a density of approximately 2.2 g/cc. Therefore, 2.2 tonnes of salt must be removed to form a 1 m^3 cavern. 7 to 10 m^3 of water is required to dissolve 1 m^3 of salt depending upon the initial water salinity and final brine saturation. Therefore, a salt cavern of 0.28 million m^3 could store 1 Bcf hydrogen (assuming hydrogen expansion factor of 100v/v) and will require 2 to 3 million m^3 water to create and this volume will need to be disposed of. 1 to 2 water supply wells would be required to provide this water within a reasonable timeframe (1-2 years).

The suitability of salt deposits as hydrogen storage options is dependent on many factors, including the storage capacity requirement, access to water and disposal of brine. Commercial factors will also have an impact such as access to infrastructure such as roads, and the physical distance from the suitable storage site and the hydrogen plant and its offtake point.

8. Modelling recommendations and data adequacy

A subsequent stage to this study is a modelling study of the high-graded fields identified in this report. Requirements and recommendations for this subsequent modelling study in addition to commentary on data adequacy are contained herein.

8.1. Modelling requirements and recommendations

Modelling of hydrogen storage in salt caverns requires only simple tank models with crestal hydrogen injection displacing basal brine. However, as in all storage options, microbial activity and corresponding hydrogen losses must also be evaluated.

Hydrogen storage in porous water bearing traps is relatively simple, requiring only two components (water and hydrogen). However, the amount of available subsurface data (wells, core) may be limited compared to depleted oil and gas fields. Seismic acquisition and appraisal drilling is likely to be required to appraise the structure and geology.

Modelling in depleted gas fields is more complex and requires the modelling of hydrogen, remaining native natural gas plus other gasses that may be used to supplement cushion gas (i.e. CO_2, nitrogen) in addition to the aquifer.

Black oil simulators typically used in the hydrocarbon energy industry cannot model two gas phases. Compositional simulation is required to accurately model the two separate gases (hydrogen and natural gas). Software commonly available and utilised by the oil and gas industry can be used to generate 3D subsurface geological models and undertake 3D compositional simulation.

Hydrogen is lower density than natural gas, with gravity or buoyancy forces acting on the gas phases hydrogen will migrate to the crest of the structure. If hydrogen is injected at the crest of the depleted gas field, mixing of hydrogen with native and/or cushion gas may be limited. If hydrogen is injected deeper in the field, buoyancy forces will make it migrate towards the crest and mix with native hydrocarbon gas and/or cushion gas.

In addition, hydrogen is 1.5 times more mobile than natural gas. Viscous forces will cause hydrogen fingering into the native and/or cushion gas. If gravity forces dominate the degree of fingering may however be limited. Limiting the rate of hydrogen injection will reduce viscous fingering and resulting gas mixing.

Literature in the public domain regarding modelling hydrogen storage in porous media is limited:

- Hydrogen injection has been simulated in a homogenous water bearing reservoir using Eclipse300 compositional simulation software[20]. Initially nitrogen was injected as cushion gas followed by hydrogen for storage. In the first cycle of hydrogen re-production the produced gas contained 52% hydrogen on average (48% nitrogen). After three cycles of hydrogen injection and re-production the produced gas contained 85% hydrogen on average.
- Scafidi[21] presented results of compositional modelling of hydrogen storage in a natural gas field. Simulation of seasonal storage over 20 years resulting in 95% hydrogen recovery with minimal mixing in

[20] Subsurface porous media hydrogen storage – scenario development and simulation. Pfeiffer and Bauer, 2015.
[21] Compositional simulation of hydrogen storage in a depleted gas field. EGU General Assembly 2021.

the reservoir. The use of natural gas as a cushion gas was shown to reduce the risk of hydrogen losses due to water coning.

- Feldmann[22] simulated cycles of hydrogen storage/production in a large onshore European gas field. Hydrogen was injected and re-produced after injecting a mixture of methane and nitrogen as cushion gas. The hydrogen concentration in the re-produced gas declined from 97% to 82% during each cycle of production. The hydrogen recovery factor is not reported.

If available, existing geological models developed for the fields development and reservoir management may be useful as a prior input to a more sophisticated compositional dynamic model. However, RISC recommends a 'ground-up' integrated subsurface modelling approach incorporating the following scope:

- Compilation of a comprehensive database, including seismic and well data.
- Review and critique of pre-existing studies, evaluations and development plans.
- Petrophysical analysis of key offset and wells from the field for reservoir characterisation, including lithological and reservoir flow-unit picks.
- Seismic interpretation and derivation of key well calibrated depth surfaces for construction of a geological static model.
- Geological reference case static model construction incorporating well and seismic interpretations and utilising appropriate workflows for populating and propagating reservoir parameters.

It is assumed that a comprehensive uncertainty analysis is not required in the modelling, such as the construction of low and high case models in addition to the reference case, nor experimental design of simulation parameters.

For screening studies simpler two-phase black oil models may provide first pass results:

- Two gases cannot be modelled in these simpler models so the remaining natural gas in the reservoir would have to be modelled as hydrogen (i.e. given the same fluid properties as the injected hydrogen).
- Tracers could be used to track injected hydrogen compared to gas originally in place and give an indication of hydrogen/original gas mixing and the proportion of injected hydrogen in the back produced gas.
- Such simpler models will have a quicker run time and potentially lower cost for software licenses. However, gravity segregation, mixed gas relative permeabilities and viscous fingering of hydrogen and natural gas is not modelled, limiting the accuracy of results.
- The simplified model results may be acceptable for screening if the volume of remaining natural gas is small compared to the planned hydrogen injection and no alternative cushion gas is to be injected.

RISC recommends that one or more of the preferred hydrogen storage fields as described in this report is selected for modelling and that both simplified and full compositional dynamic modelling is conducted to evaluate the hydrogen storage potential and the short comings from simplified modelling.

8.2. Data adequacy

A key advantage of assessing and modelling depleted fields over aquifer traps is that the available data (i.e. seismic data, well control, log data, core, laboratory analyses) is more readily available and likely to provide a comprehensive database for hydrogen storage modelling.

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[22] Numerical simulation of hydrodynamic and gas mixing processes in underground hydrogen storage. Environmental Earth Science, Feldman 2016.

It is assumed for the modelling project that documentation, data and analysis that are publicly available or open file are utilised and that no new additional data acquisition or analysis are conducted.

All the depleted oil and gas fields assessed in this report, including those recommended for the modelling stage, are covered with 3D seismic data. This is ideal for the construction of a geological static model which will not be compromised by the uncertainties of subsurface structure offered by 2D seismic coverage alone.

A review of the 3D seismic data quality, nor the processing vintage publicly available, was not undertaken by RISC as part of this study. It is therefore assumed that for the modelling study the most recent publicly available processing vintage will be utilised for the seismic interpretation as input to the geologic static modelling.

Geomechanical data is also likely to be available from hydrocarbon development studies and can be used to estimate maximum hydrogen pressure and columns, so as not to rupture cap rock.

RISC has not identified any data adequacy issues in regard to a subsequent modelling project. However, RISC notes the following:

- Hydrogen relative permeability in a mixed gas system is a key uncertainty. Similarly, the relative permeability of natural gas in the presence of hydrogen is also an uncertainty. It may then be prudent to undertake further literature searches and core analysis to estimate and confirm relative permeabilities.
- Although not common, geochemical reaction of hydrogen with kerogen, clays and minerals in the cap rock can result in hydrogen losses and affect caprock integrity. A review of, and possibly additional laboratory tests with core may be required.
- The risk of sulphur reducing bacteria souring the stored hydrogen with H_2S must be evaluated. This will require a review of previous research and possible additional laboratory work with core.
- Field tests indicate that standard gas storage facilities are suitable with up to 20% hydrogen. However, experience with pure hydrogen storage is limited. The risk of metallurgy and more likely valve seal and elastomer failure needs to be confirmed.

RISC notes that following the completion of a modelling study, shortcomings and adequacy of the available data will be further quantified and that recommendations regarding the acquisition of new data should be expected.

8.3. Modelling study timeframe

A modelling study would have considerable scope as outlined above, consequently it would be expected that modelling of one depleted field would take 2 – 3 months. Should the scope include more than one field, then it is reasonable to anticipate that timing would as a consequence increase.

If the hydrocarbon field evaluation, development plan and pre-existing models are available, or the inputs to geological modelling such as petrophysical analyses and seismic interpretations, then the scope and timing of a study could therefore be reduced. Converting and evaluating the dynamic models for a hydrogen storage study could be completed in a few weeks.

However, RISC opinion is that recycling or utilising existing modelling and studies without comprehensive quality control may adversely affect the quality of the results.

Any additional geomechanical, geochemical and microbial studies as afore mentioned could be conducted in parallel with the modelling work.

The Indicative scope and timeframe are for an evaluation and modelling feasibility study only. Progressing any hydrogen storage opportunity through front-end engineering and design (‘FEED’) in addition to the required regulatory and environmental approvals prior to a final investment decision is not included.

9. Declarations

9.1. Terms of Engagement

This report, any advice, opinions or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by the Client and RISC.

9.2. Qualifications

RISC is an independent oil and gas advisory firm. All the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years.

9.3. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances or regulations that apply to these assets.

We believe our review and conclusions are sound, but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

9.4. Use of advice or opinion and reliance

We understand that the client will make the Report a public document. The Report is for benefit of the Client and ***may not be relied upon by any 3rd party.***

9.5. Independence

RISC makes the following disclosures:

- RISC is independent with respect to DMIRS and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and DMIRS, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report.
- Neither RISC Directors nor any staff involved in the preparation of this report have any material interest in the Client or in any of the properties described herein.

9.6. Copyright

10. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

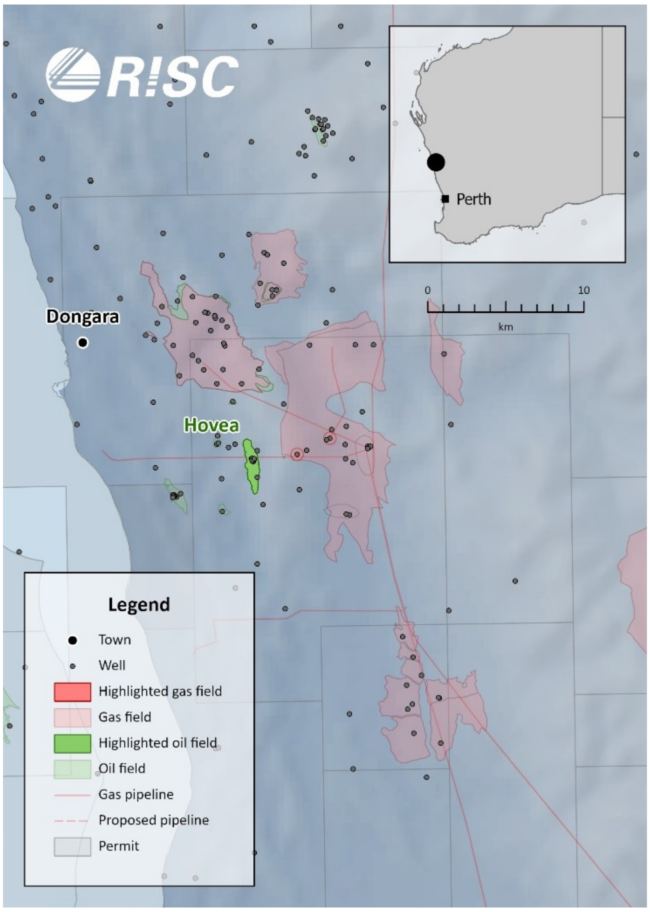
Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2D	Two Dimensional
3D	Three Dimensional
4D	Four Dimensional – time lapsed 3D in relation to seismic
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
AOF	Absolute Open Flow (maximum well flowrate with atmospheric pressure at perforations)
Bbl	US Barrel
BBL/D	US Barrels per day
Bcf	Billion (10^9) cubic feet
Bcm	Billion (10^9) cubic metres
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
°C	Degrees Celsius
CGR	Condensate Gas Ratio – usually expressed as bbl/MMscf
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO_2	Carbon dioxide
CP	Centipoise (measure of viscosity)
DEG	Degrees
DST	Drill stem test
E&P	Exploration and Production
EG	Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions (pressure and temperature)
EOR	Enhanced Oil Recovery
EUR	Economic ultimate recovery
Expectation	The mean of a probability distribution
F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FWL	Free Water Level
FVF	Formation volume factor
GIIP	Gas Initially In Place
GOC	Gas-oil contact

Term	Definition
GOR	Gas oil ratio
GRV	Gross rock volume
GWC	Gas water contact
H_2S	Hydrogen sulphide
HHV	Higher heating value
JV(P)	Joint Venture (Partners)
Kh	Horizontal permeability
km^2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilo (thousand) Pascals (measurement of pressure)
Mstb/d	Thousand Stock tank barrels per day
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MJ	Mega (10^6) Joules
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)
MMstb	Million US stock tank barrels
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
MSV	Mean Success Volume
mTVDss	Metres true vertical depth subsea
NTG	Net to Gross (ratio)
ODT	Oil down to
OGIP	Original Gas In Place
OOIP	Original Oil in Place
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
PJ	Peta (10^{15}) Joules
psia	Pounds per square inch pressure absolute
PVT	Pressure, volume & temperature
RFT	Repeat Formation Test
RT	Measured from Rotary Table or Real Terms, depending on context
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
Sgr	Residual gas saturation

Term	Definition
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
Tcf	Trillion (10^{12}) cubic feet
TJ	Tera (10^{12}) Joules
TVD	True vertical depth
TWh	Trillion (10^{9}) Watt Hours
WCR	Well Completion Report

Appendix A – Field descriptions

Hovea Field Description

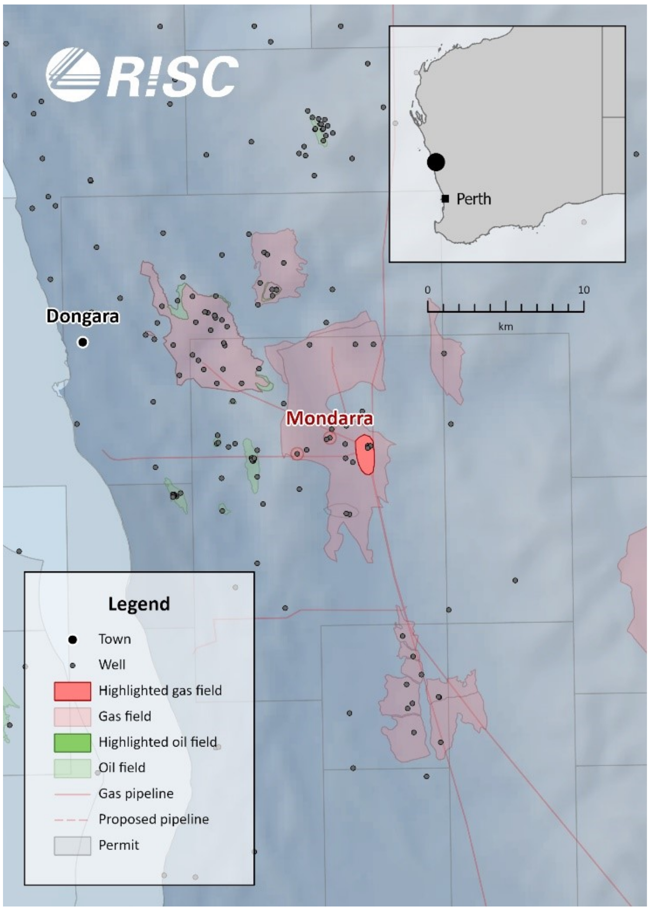


Permit	L 1/ L 2
Basin	Perth Basin
Reservoir	Dongara Sandstone
Main hydrocarbon	Oil
Discovery well	Hovea-1
Production start	Late 2002
Production end	Late 2004
Production	Oil: 7.3 MMstb Gas: 3.7 Bcf

Reservoir properties (Hovea-1 Structure)

Depth	1996 m
Initial Reservoir pressure	N/A
Reservoir temperature	N/A
Reservoir thickness (gross)	50 m
Net to gross	90%
Porosity	12 to 18%
Permeability	600 mD

Mondarra Field Description



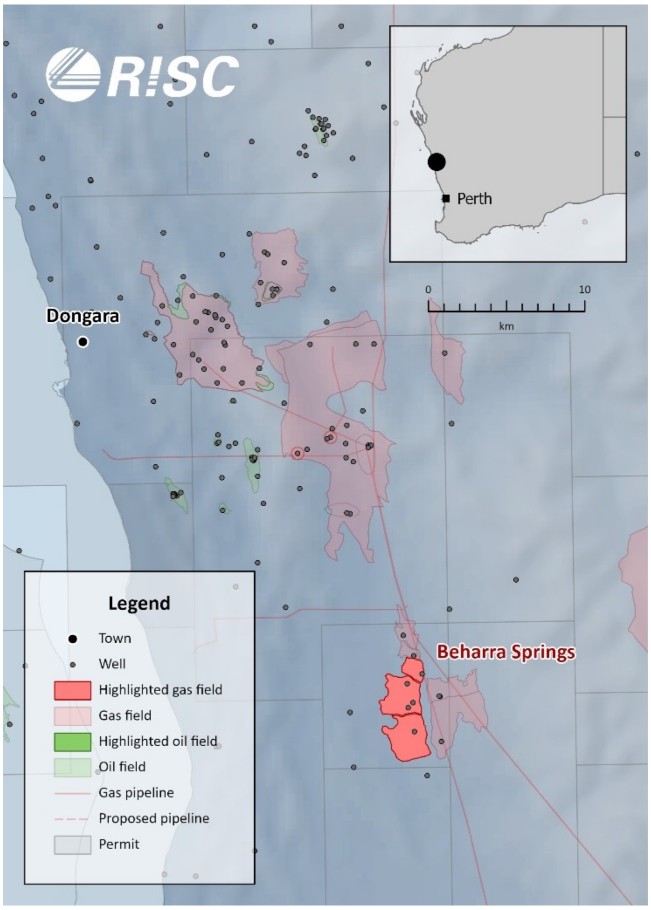
Permit	L 1/EP 23/LP1-171H
Basin	Perth Basin
Reservoir	Dongara Sandstone
Main hydrocarbon	Gas
Discovery well	Mondarra-1
Production start	1972
Production end	1994*
Production	Condensate: 0.06 MMstb Gas: 23.9 Bcf

* Note that Mondarra is currently operating as a gas storage facility

Reservoir properties (Mondarra-1 Structure)

Depth	2602m (top reservoir)
Initial Reservoir pressure	4255 psia
Reservoir temperature	102 deg C
Reservoir thickness (gross)	46 m
Net to gross	70%
Porosity	15%
Permeability	127 mD

Beharra Springs Field Description

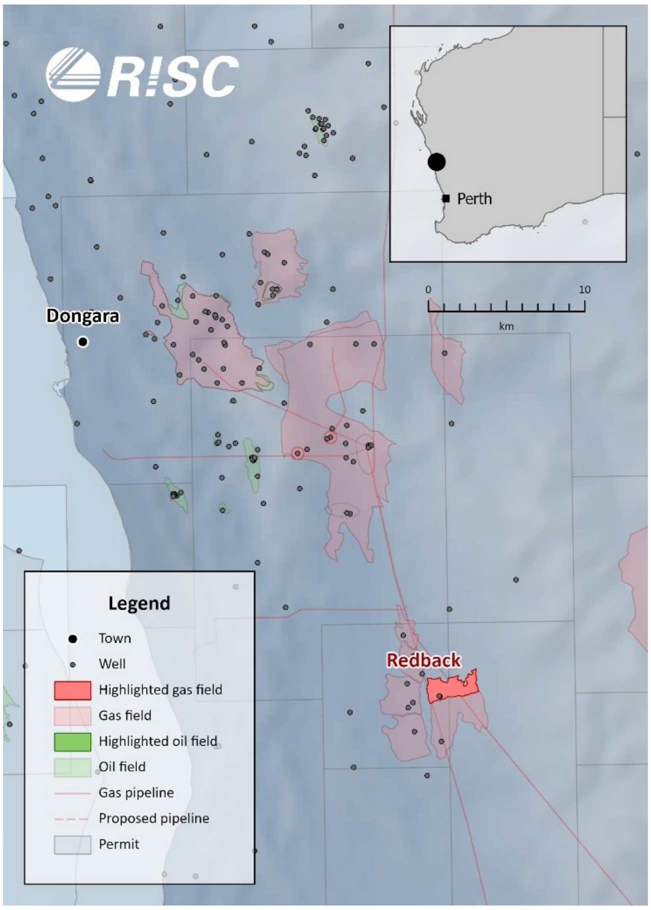


Permit	L 11
Basin	Perth Basin
Reservoir	Wagina Sandstone
Main hydrocarbon	Gas
Discovery well	Beharra Springs 1
Production start	1991
Production end	After 2015
Production to 2015	Condensate: 0.2 MMstb Gas: 89 Bcf

Reservoir properties (Beharra Springs-1 Structure – Upper Sandstone)

Depth	3250 m (top reservoir)
Initial Reservoir pressure	4975 psia
Reservoir temperature	141 deg C
Reservoir thickness (gross)	20 m
Net to gross	62.5%
Porosity	13%
Permeability	514 mD

Redback Field Description

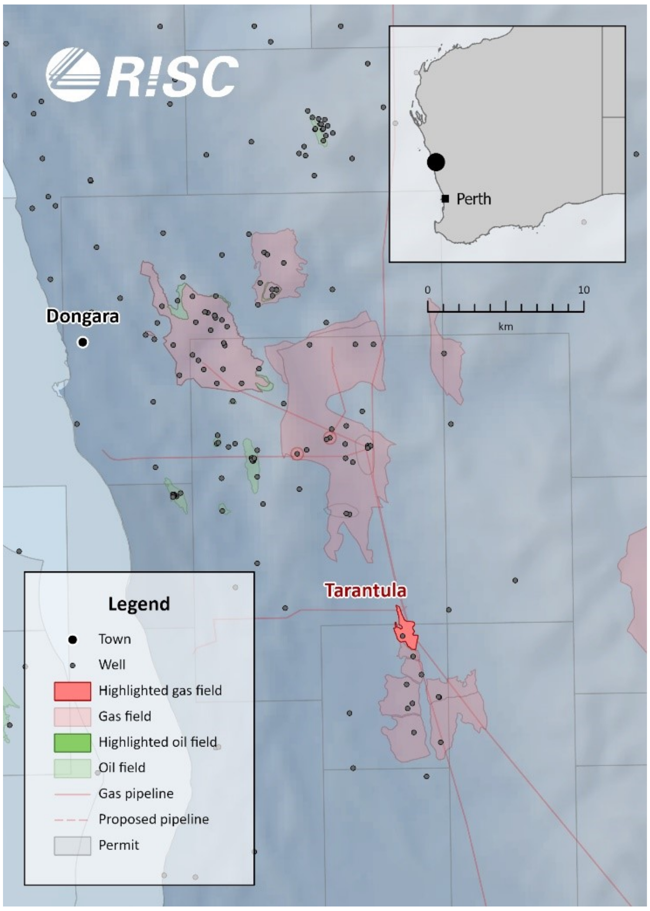


Permit	L 11
Basin	Perth Basin
Reservoir	Wagina Sandstone
Main hydrocarbon	Gas
Discovery well	Redback-1
Production start	1992
Production end	After 2015
Production to 2015	Condensate: 0.01 MMstb Gas: 22 Bcf

Reservoir properties (Redback South-1 Structure – Upper Sandstone)

Depth	3775 m (top reservoir)
Initial Reservoir pressure (mid-perf)	5263 psia
Reservoir temperature	150 deg C
Reservoir thickness (gross)	6 m
Net to gross	53%
Porosity	14%
Permeability	237 mD

Tarantula Field Description

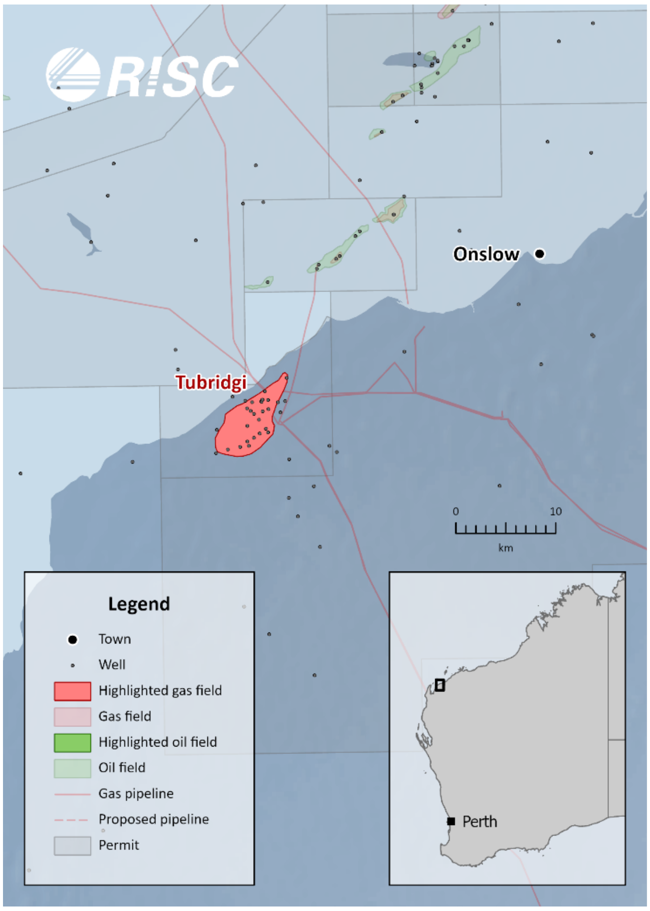


Permit	L 11
Basin	Perth Basin
Reservoir	Wagina Sandstone
Main hydrocarbon	Gas
Discovery well	Tarantula-1
Production start	2005
Production end	After 2015
Production to 2015	Condensate: 0.03 MMstb Gas: 12.7 Bcf

Reservoir properties (Lower Sandstone)

Depth	3228 mRT (top of lower sandstone)
Initial Reservoir pressure	N/A
Reservoir temperature	N/A
Reservoir thickness (gross)	11 m
Net to gross	51%
Porosity	11%
Permeability	17.6 mD

Tubridgi Field Description



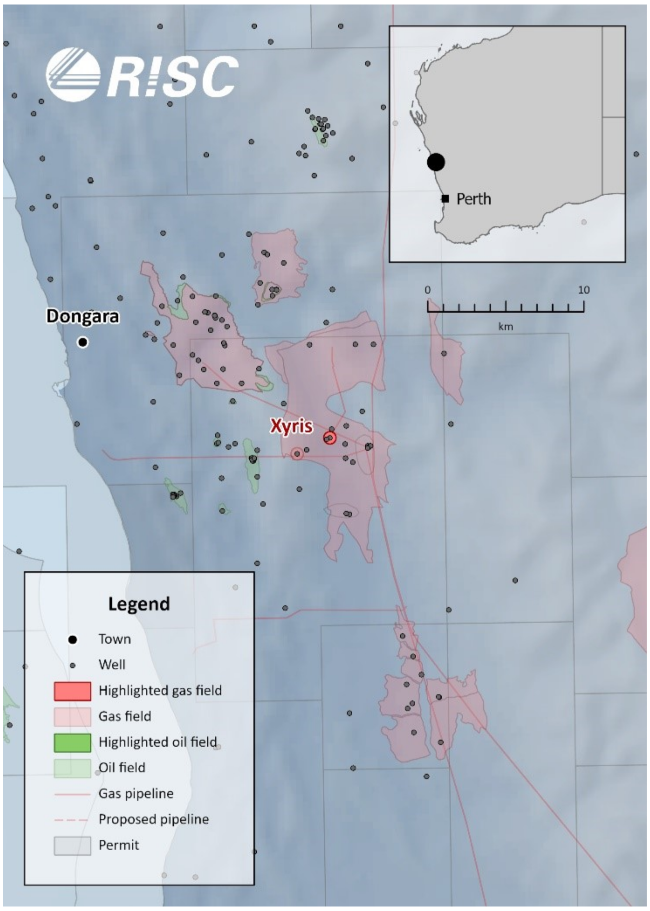
Permit	L 9
Basin	Southern Carnarvon
Reservoir	Birdrong, Flacourt, Mungaroo Sandstones
Main hydrocarbon	Gas
Discovery well	Tubridgi-1
Production start	1991
Production end	2005*
Production	Condensate: minor Gas: 69.0 Bcf

* Note that the Tubridgi field is currently operating as a gas storage facility.

Reservoir properties (Tubridgi-1, Tyrbridgi-9)

Depth	518 m (top reservoir)
Initial Reservoir pressure	~ 700 psia
Reservoir temperature	~40 deg C
Reservoir thickness (gross)	40 m
Net to gross	N/A
Porosity	15 - 35% (average 26%)
Permeability	3 – 600 mD (average 10 mD)

Xyris Field Description

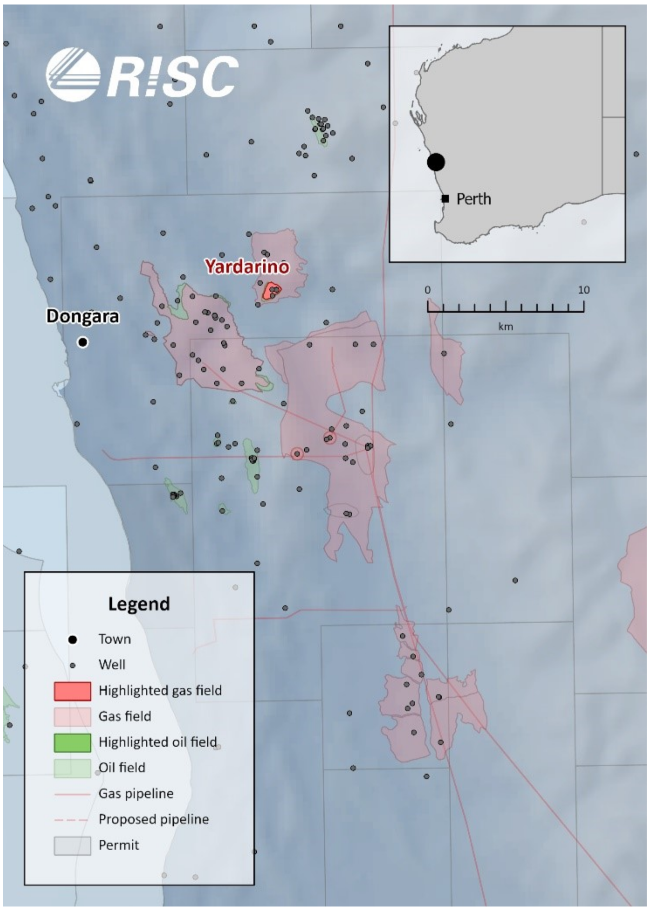


Permit	L 1
Basin	Perth
Reservoir	Dongara Sandstone
Main hydrocarbon	Gas
Discovery well	Xyris-1
Production start	2004
Production end	2010
Production	Condensate: 0.02 MMstb Gas: 9.3 Bcf

Reservoir properties (Xyris-1 Structure)

Depth	2574 m (top reservoir)
Initial Reservoir pressure	N/A
Reservoir temperature	N/A
Reservoir thickness (gross)	69 m
Net to gross	30%
Porosity	11%
Permeability	123 – 2078 mD (taken from nearby Hovea-3 well)

Yardarino Field Description

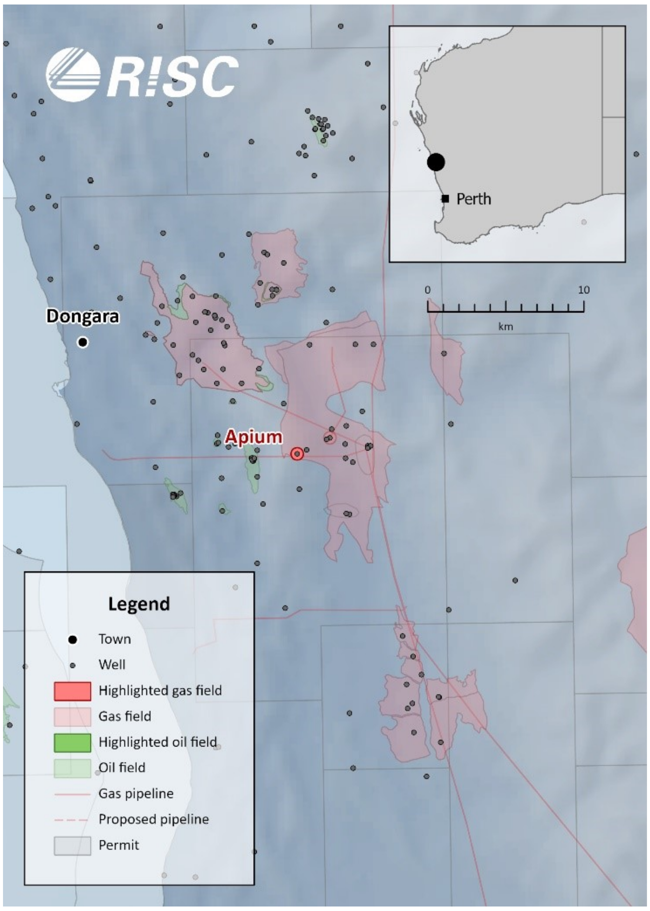


Permit	L 2 & LP-111H
Basin	Perth Basin
Reservoir	Dongara Sandstone
Main hydrocarbon	Gas
Discovery well	Yardarino-1
Production start	1978
Production end	2010
Production	Condensate: 0.01 MMstb Gas: 5.08 Bcf

Reservoir properties (Yardarino-1)

Depth	**2238 m (top reservoir)**
Initial Reservoir pressure	3395 psia
Reservoir temperature	97.1 deg C
Reservoir thickness (gross)	15 m
Net to gross	93%
Porosity	15%
Permeability	200 mD

Apium Field Description

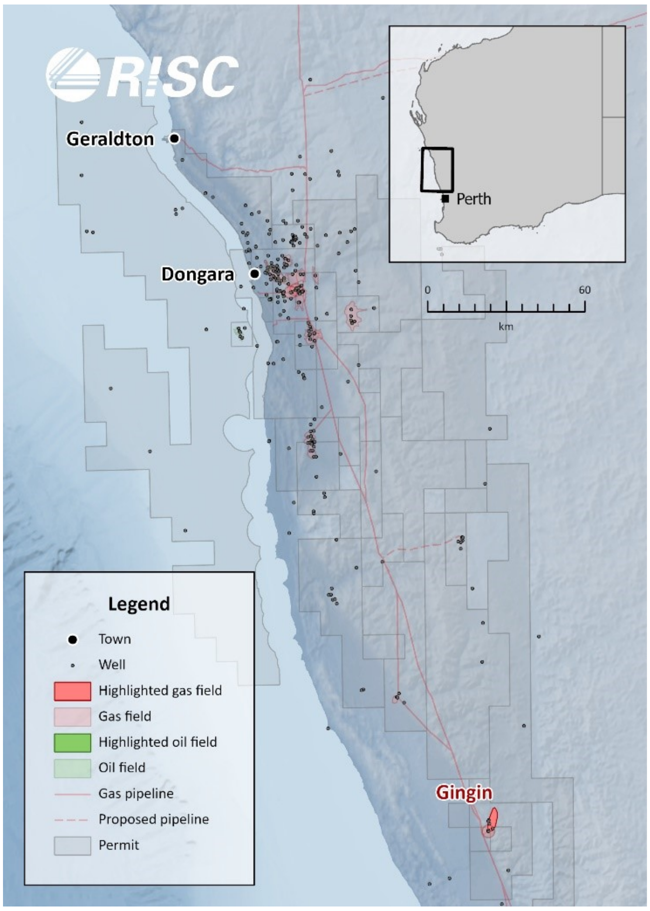


Permit	L 1
Basin	Perth Basin
Reservoir	Dongara sandstone
Main hydrocarbon	Gas
Discovery well	Apium-1
Production start	2007
Production end	2012
Production	Condensate: 0.00 MMstb Gas: 1.19 Bcf

Reservoir properties (Apium-1)

Depth	2630 m (pressure gauge)
Initial Reservoir pressure	3874 psia
Reservoir temperature	114 deg C
Reservoir thickness	~9 m (perforated pay zone)
Net to gross	N/A
Porosity	8.5%
Permeability	4.5 mD

Gingin Field Description

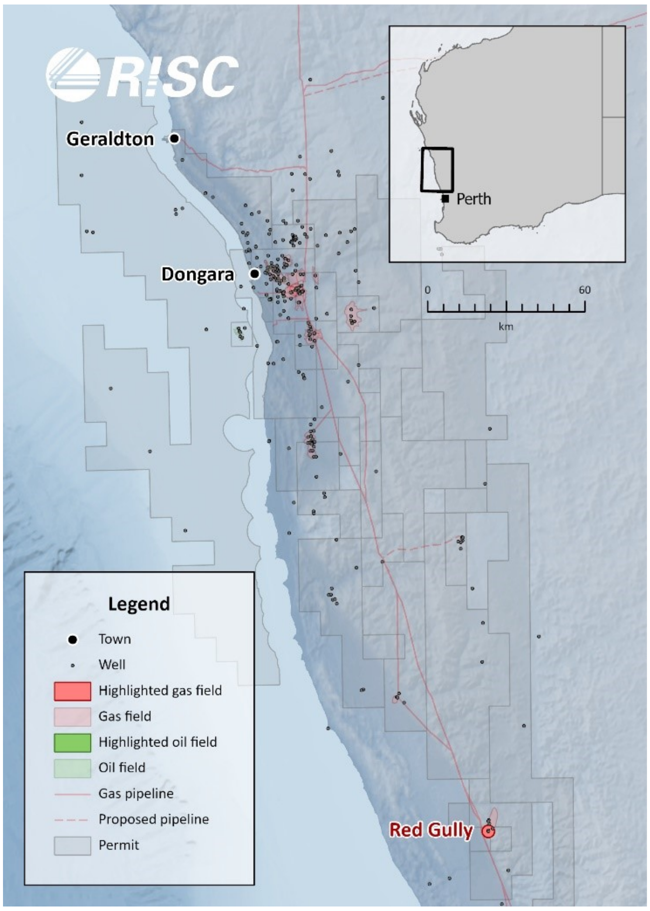


Permit	EP 389, L 18, L 19
Basin	Perth Basin
Reservoir	Cattamarra Coal Measures
Main hydrocarbon	Gas
Discovery well	Gingin-1
Production start	1972
Production end	1976
Production	Condensate: 0.02 MMstb Gas: 1.71 Bcf

Reservoir properties (Gingin-1 Structure)

Depth	3661 m (top reservoir)
Initial Reservoir pressure	N/A
Reservoir temperature	N/A
Reservoir thickness (gross)	300 m
Net to gross	N/A
Porosity	8%
Permeability	70 mD

Red Gully Field Description

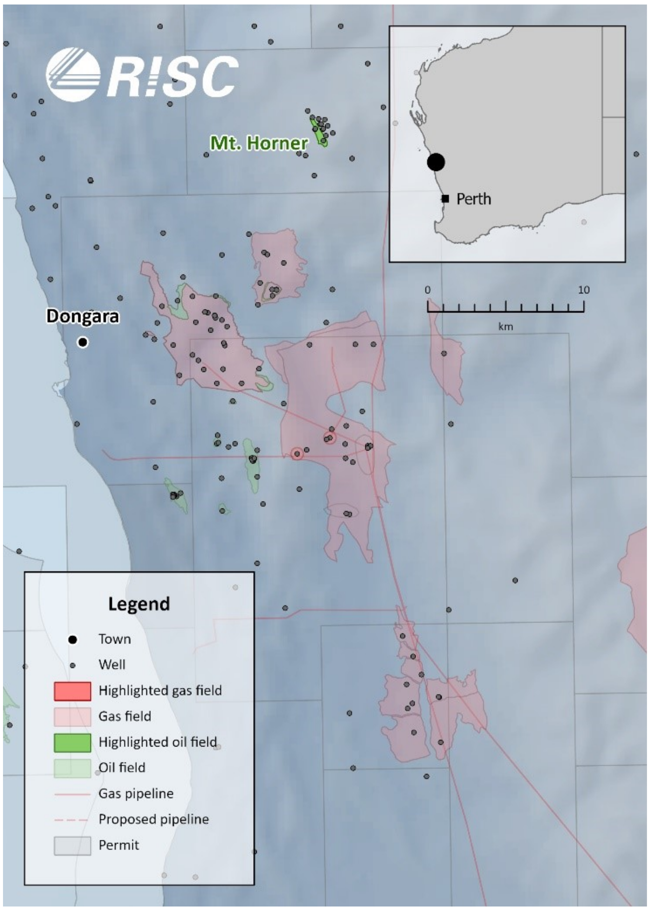


Permit	EP 389, L 18, L 19
Basin	Perth Basin
Reservoir	Cattamarra Coal Measures
Main hydrocarbon	Gas
Discovery well	Red Gully-1
Production start	2013
Production end	After 2015
Production to 2015	Condensate: 0.20 MMstb Gas: 4.01 Bcf

Reservoir properties (Sand Member D)

Depth	3735 m (top reservoir)
Initial Reservoir pressure	N/A
Reservoir temperature	N/A
Reservoir thickness (gross)	20 m
Net to gross	N/A
Porosity	11% - 13%
Permeability	4.5 – 23 mD

Mount Horner Field Description

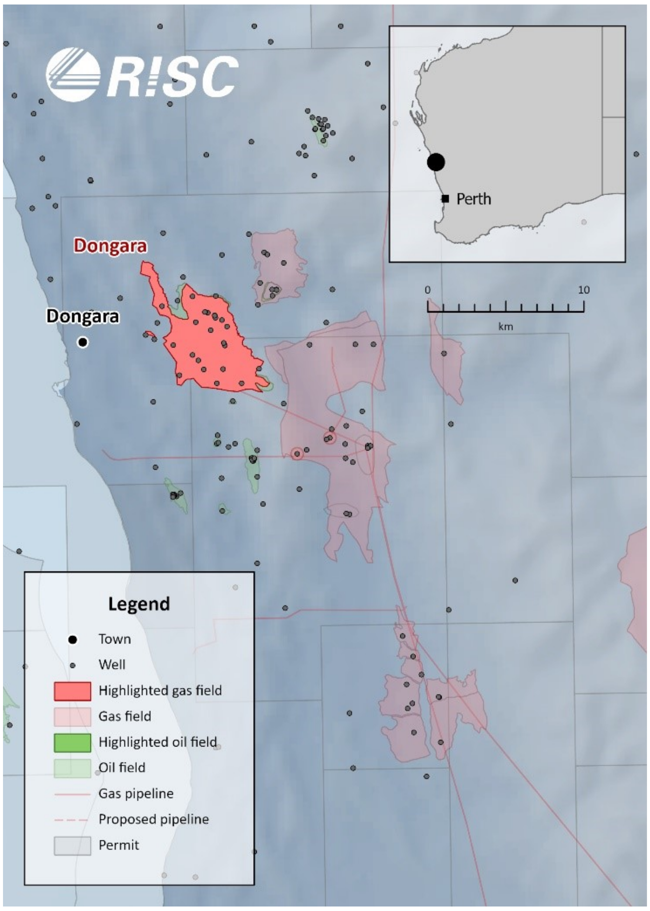


Permit	L 7
Basin	Perth Basin
Reservoir	Cattamarra Coal Measures
Main hydrocarbon	Gas
Discovery well	Mt Horner-1
Production start	1984
Production end	2011
Production	Oil: 1.9 MMstb Gas: 0.0 Bcf

Reservoir properties (F Sand)

Depth	**1015 m (top reservoir)**
Initial Reservoir pressure	1555 psig
Reservoir temperature	75.5 deg C
Reservoir thickness (gross)	7.5 – 10 m
Net to gross	31 – 88%
Porosity	14 – 27%
Permeability	86 – 380 mD

Dongara Field Description



Permit	L 1, L 2
Basin	Perth Basin
Reservoir	Dongara Sandstone
Main hydrocarbon	Gas
Discovery well	Dongara-1
Production start	1972
Production end	After 2015
Production	Oil: 1.54 MMstb Gas: 457 Bcf

Reservoir properties (Multiple wells)

Depth	1622 m (top reservoir in Dongara-1)
Initial Reservoir pressure	2457 psia
Reservoir temperature	72.2 deg C
Reservoir thickness (gross)	11 – 39 m
Net to gross	28 – 100%
Porosity	15 – 28%
Permeability	26 to 648 mD

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Appendix C – Workshop presentation materials

Underground Hydrogen Storage Workshop

Agenda

14:00 AWST	Welcome and introductions
14:10 AWST	RISC presentation *Stephen Newman – Underground hydrogen storage, implications for WA*
14:40 AWST	Brief presentations from select participants (5-10min each) *Jonathan Ennis King (CSIRO)* *Katriona Edlmann (University of Edinburgh – HyStorPor)* *Andrew Feitz (Geoscience Australia)* *Markus Pichler (RAG)*
15:30 AWST	Open floor discussion
16:00 AWST	Summary & close.

Attendees

Name	Affiliation	email	Project	
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Jonathan Ennis King	CSIRO	Jonathan.Ennis-King@csiro.au		https://research.csiro.au/hydrogenfsp/our-research/projects/our-research-in-underground-hydrogen-storage-in-australia/
Joel Sarout	CSIRO	Joel.Sarout@csiro.au		https://research.csiro.au/hydrogenfsp/our-research/projects/impact-of-hydrogen-on-underground-reservoir-properties-laboratory-characterisation-reservoir-conditions/
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Markus Pichler	RAG	Markus.Pichler@rag-austria.at	UG Sun Storage	https://www.underground-sun-storage.at/en/
2 x attendees	HOT	office@uest.at		https://uest.at/wp-content/uploads/2021/04/UEST_UndergroundEnergyStorageTechnologies.pdf
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Chris Elders	Curtin University	chris.elders@curtin.edu.au		

RISC

decisions with confidence

Review of WA hydrogen subsurface storage potential

Industry workshop 21 July 2021

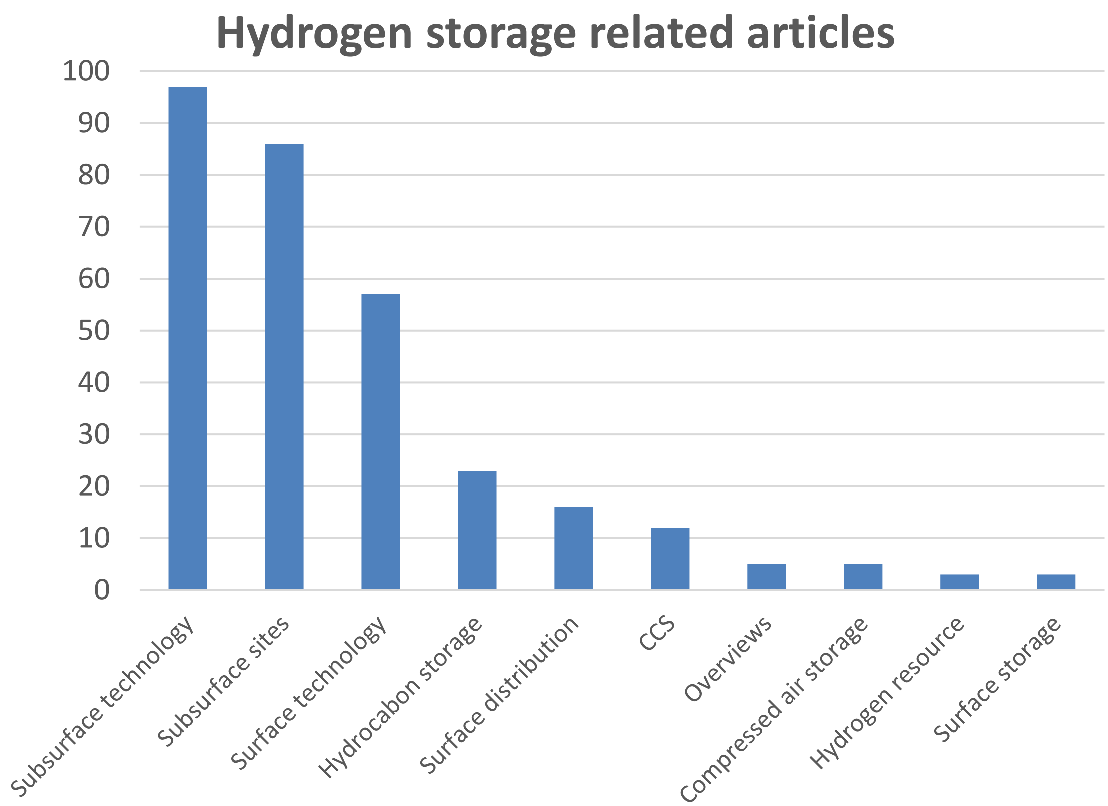
Premise for RISC study

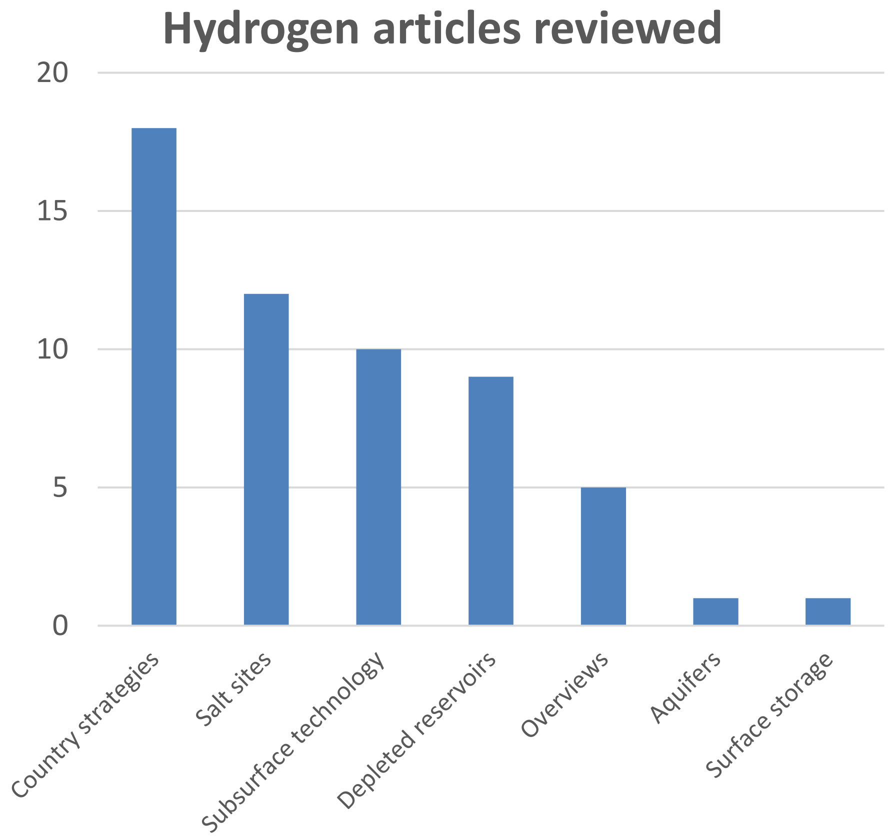
- The Government of Western Australia has developed a renewable hydrogen strategy and roadmap with a vision that Western Australia will become a significant producer, exporter and user of renewable hydrogen
- Several world scale renewable energy sites and several smaller sites are being considered in WA which will produce hydrogen such as:
  - Western Green Energy Hub (50 GW)
  - Asian renewable hub (26 GW)
- It is likely that there will be a need to develop transitory storage of the hydrogen produced, especially due to distance of the sites to end users
- The premise is that the need will be to recover hydrogen in a pure form rather than low concentrations in hydrocarbon gas
- DMIRS asked RISC to do a review of subsurface storage options, although we note that surface and chemical storage options are also being considered by the industry
  - ammonia is part of many of the renewable project plans

Western Australia's renewable portfolio is second to none

Sun, wind and space

Part 1 literature review – 340+ articles and counting!

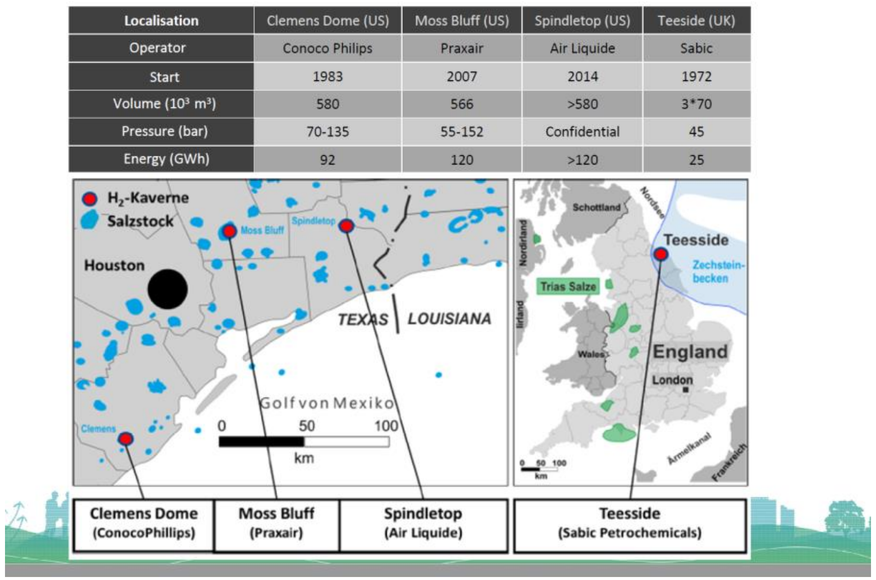




High level of interest in hydrogen as a solution to GHG emissions

Where is hydrogen currently being stored?

- There are only a handful of subsurface sites are currently used to store hydrogen
- Only 4 of these store 'pure' hydrogen
    - All of them in salt
    - Volumes are small by oil and gas fields – a few Bscf


4 sites of Hydrogen Storage in Salt Caverns in the world

Localisation	Clemens Dome (US)	Moss Bluff (US)	Spindletop (US)	Teeside (UK)
Operator	Conoco Philips	Praxair	Air Liquide	Sabic
Start	1983	2007	2014	1972
Volume (10^3 m^3)	580	566	>580	3*70
Pressure (bar)	70-135	55-152	Confidential	45
Energy (GWh)	92	120	>120	25

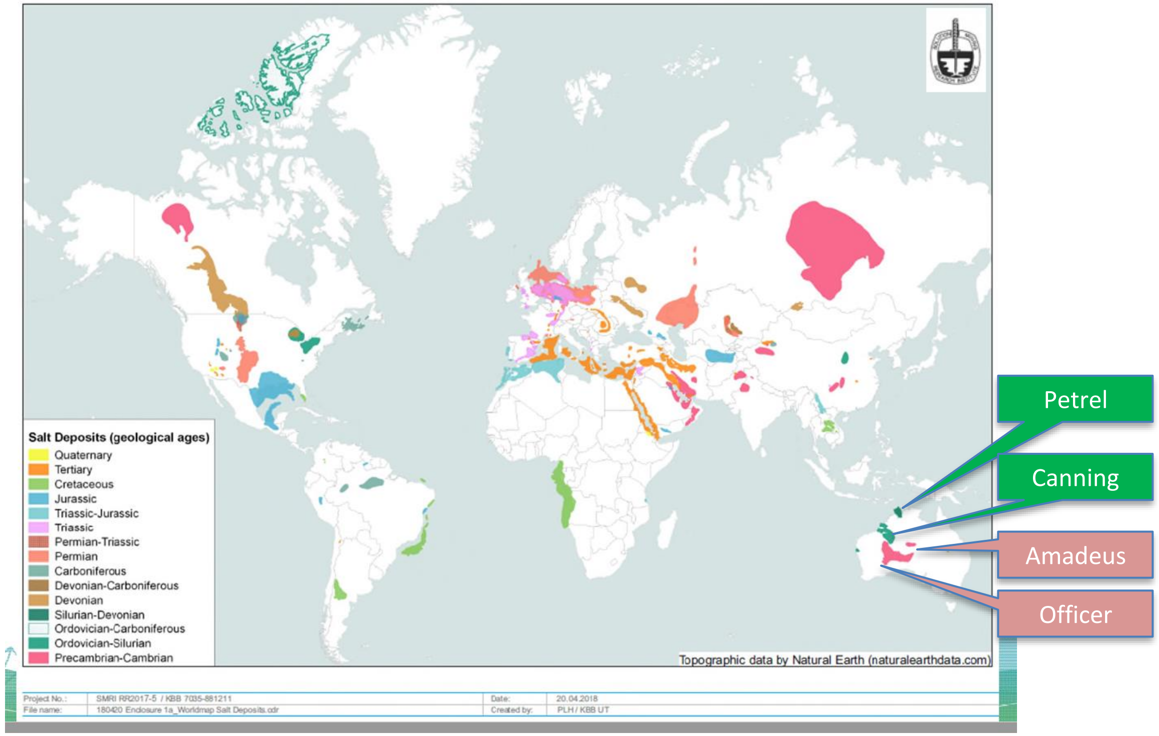
Country	Field	Storage type	Depth (m)	H_2 %	Volume (10^3 m^3)	Volume (Bscf)*
USA	**Spindletop**	**Salt dome**		**95**	**906**	**2.5**
USA	**Clemens Dome**	**Salt dome**	**800**	**95**	**580**	**0.92**
USA	**Moss Bluff**	**Salt dome**	**800**	**?**	**566**	**1.2**
UK	**Teeside**	**Bedded salt**	**350-400**	**95**	**210**	**0.23**
France	Beynes	Aquifer		50	330,000	586
Germany	Keil	Salt cavern		60	32	2.5
Germany	Ketzin	Aquifer		62		?
Czech republic	Lobodice	Aquifer		50		?
Argentina	Diadema (HyChico?)	Depleted gas reservoir		10		?
Austria	Underground Sun Storage (RAG)	Depleted gas reservoir		10		?

* Ball park estimates

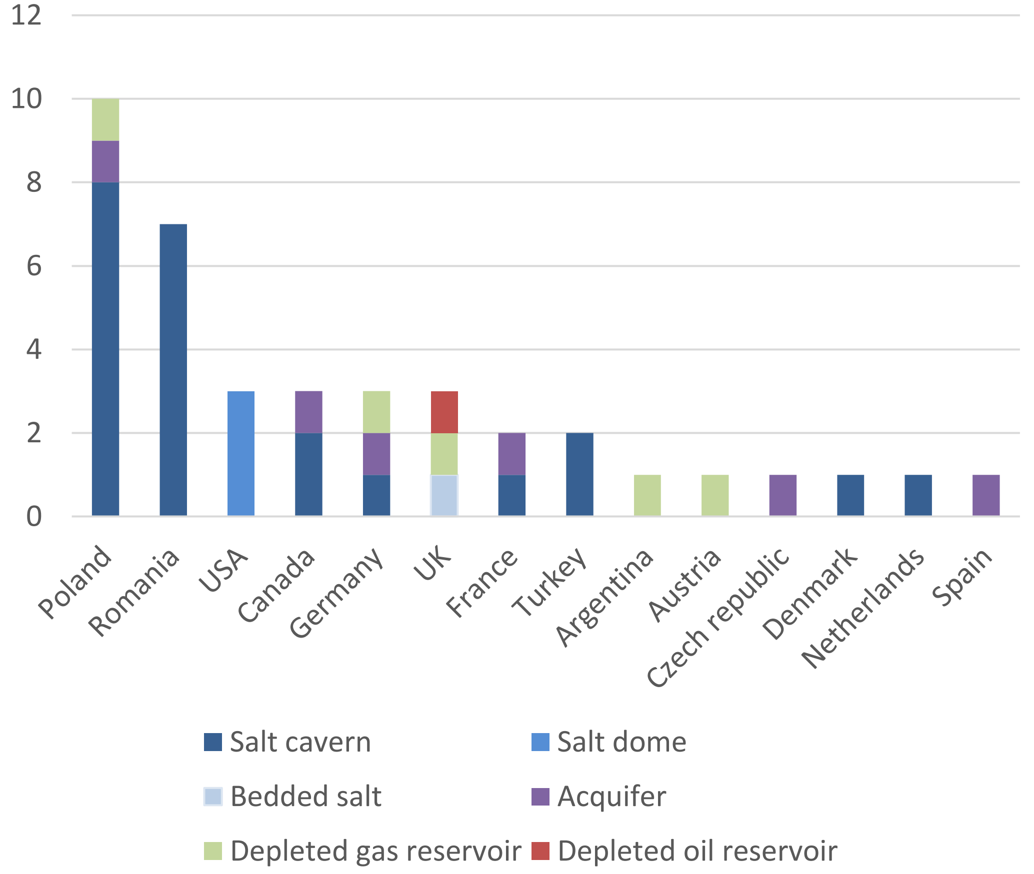
Where are new hydrogen storage sites being considered?

- Salt caverns are by far the prime focus for new hydrogen storage sites
- Poland and Romania dominate due to location of Permian and Triassic salt deposits and proximity to Europe
- Some salt dome sites being considered in the USA

Salt deposits in the world



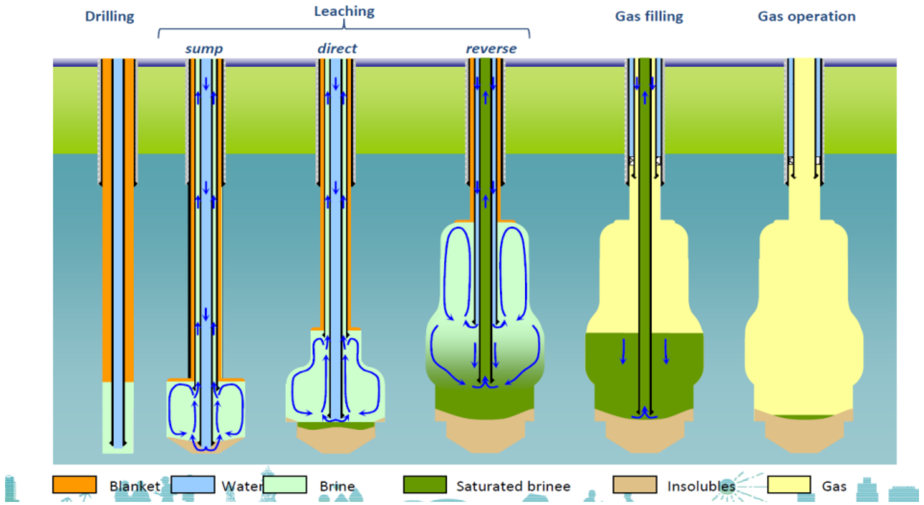
Hydrogen storage sites under consideration



Many countries are reviewing their hydrogen storage options

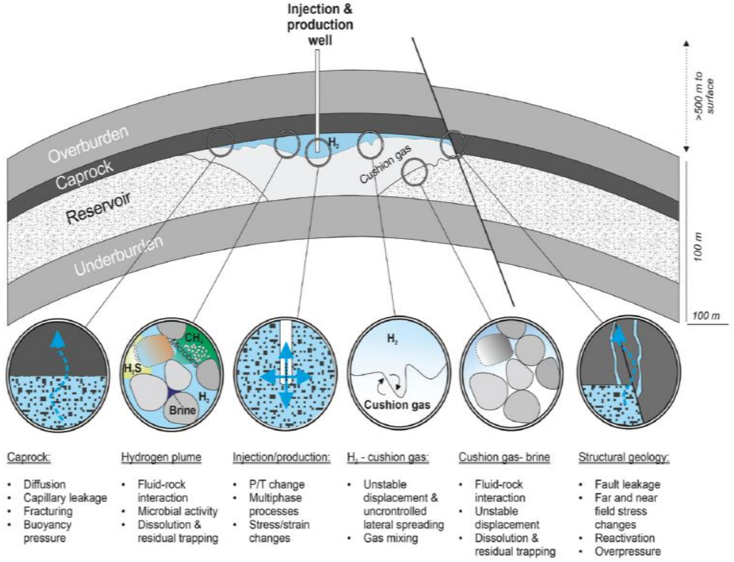
Subsurface storage options

Salt caverns



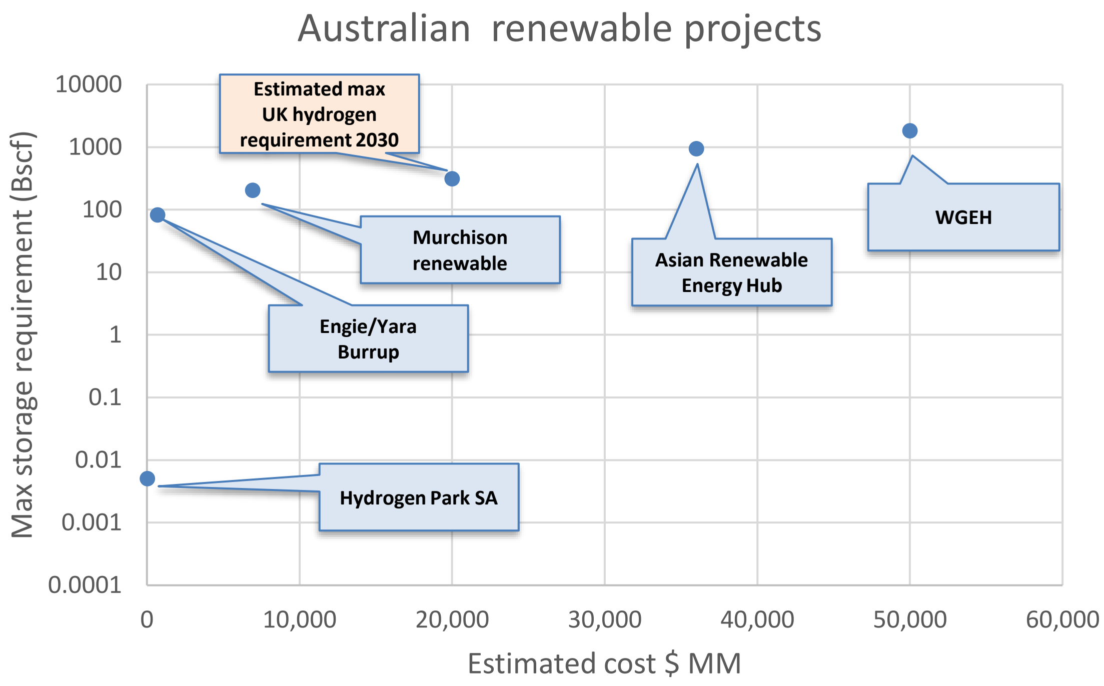
- Manufactured by dissolving salt in water and can be customised to operational requirements
- Very low permeability contains the hydrogen
- Relatively high recovery and a recharge time in the order of days/weeks.
- Most robust means of storing hydrogen and has been proved to work
- Drawback is they need access to large amounts of water in their manufacture and need a means to dispose of the generated brine – a particular issue in Australia

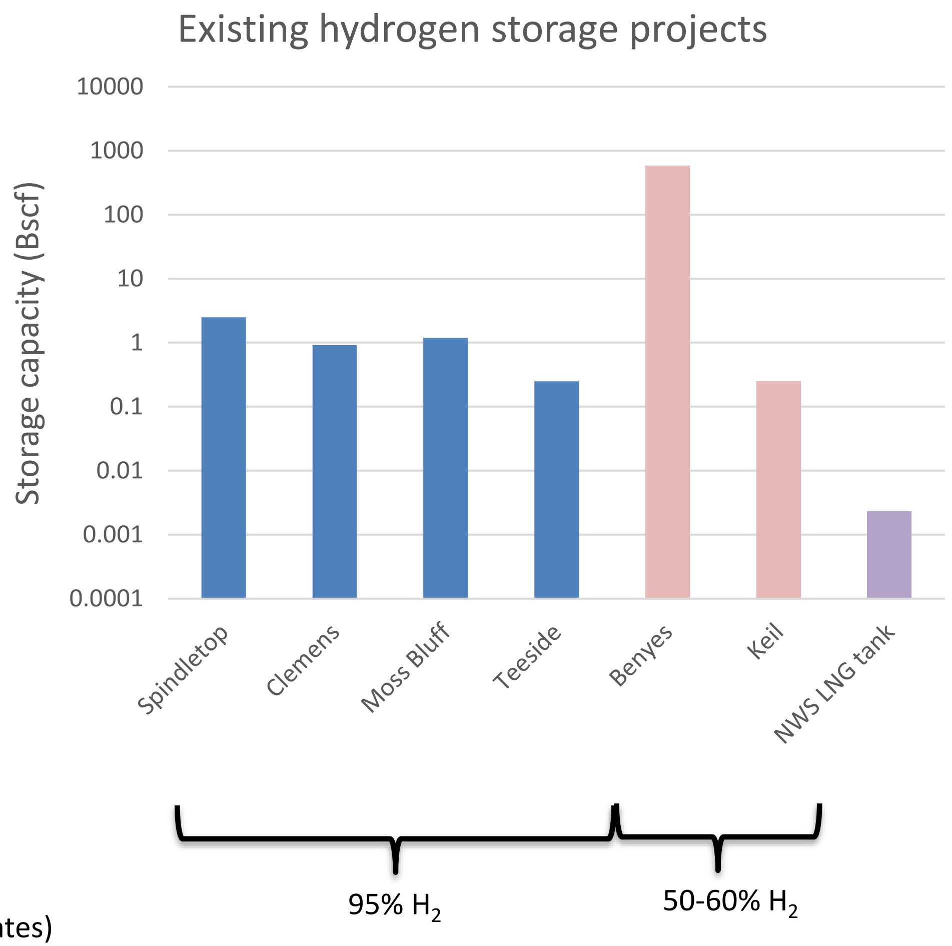
Porous media (depleted gas and oil fields or aquifers)



- Presents several challenges and remains unproven.
- The physical behaviors and properties of hydrogen is more chemically reactive that natural gas which may impact reservoir quality, flow behaviour and seal capacity.
- Hydrogen also an energy source for subsurface microbial processes which can turn the hydrogen into methane or hydrogen sulphide
- The size of the site is fixed and cannot be customised to operational requirements – and risk of high percentage of cushion gas
- Recharge time in the order of months due to relatively low permeability of reservoir to salt caverns

Benchmarking WA storage requirements





Maximum storage requirement assumptions:

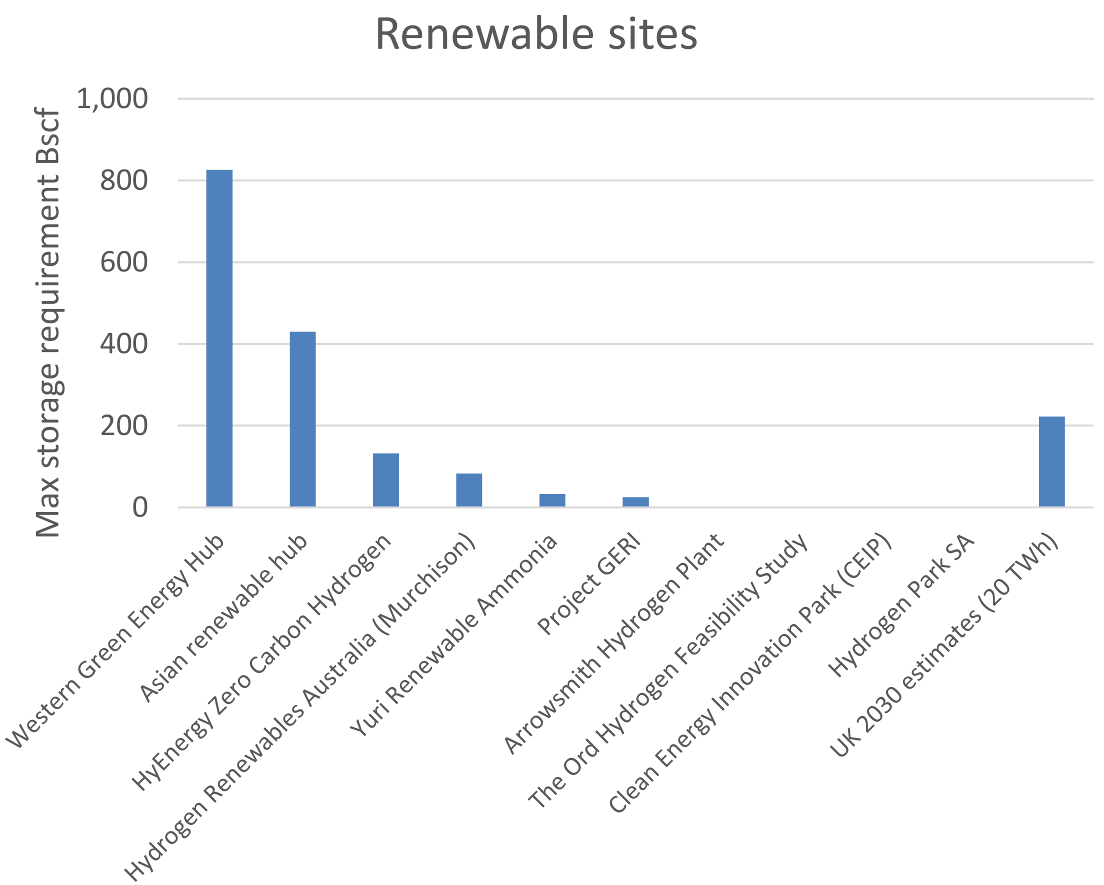
- All stated target capacity is used to generate locally used hydrogen (unlikely)
- Assume renewable sources operate 30% capacity
- Required to store 30% of annual hydrogen production (EU gas average ~ 20%)
- Does not account for energy needed to transport, compress and store hydrogen
- We note the stated target capacities will require huge investment (order of magnitude cost estimates)

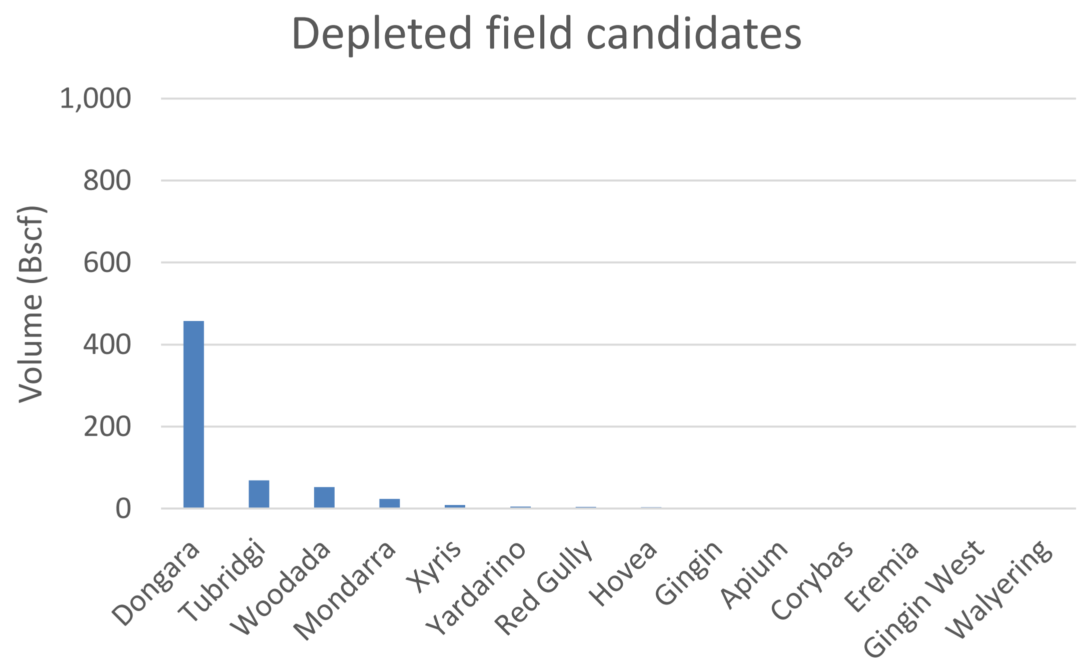
- **The WA subsurface hydrogen storage capacity required for individual sites could be material**
- Size could be consistent with existing storage projects and bigger than NWS LNG storage tanks

Potential storage location screening criteria

- RISC have used the following criteria to screen depleted fields for hydrogen storage:
  - Location – onshore is preferable
  - Type of fluid (gas preferable to oil)
  - Existing infrastructure
  - Oil and gas production data to determine if sufficient storage volume is available
  - Formation thickness, net to gross and permeability, to ensure sufficient productivity
  - Drive mechanism, aquifer support preferable

WA proposed renewable and potential subsurface storage sites



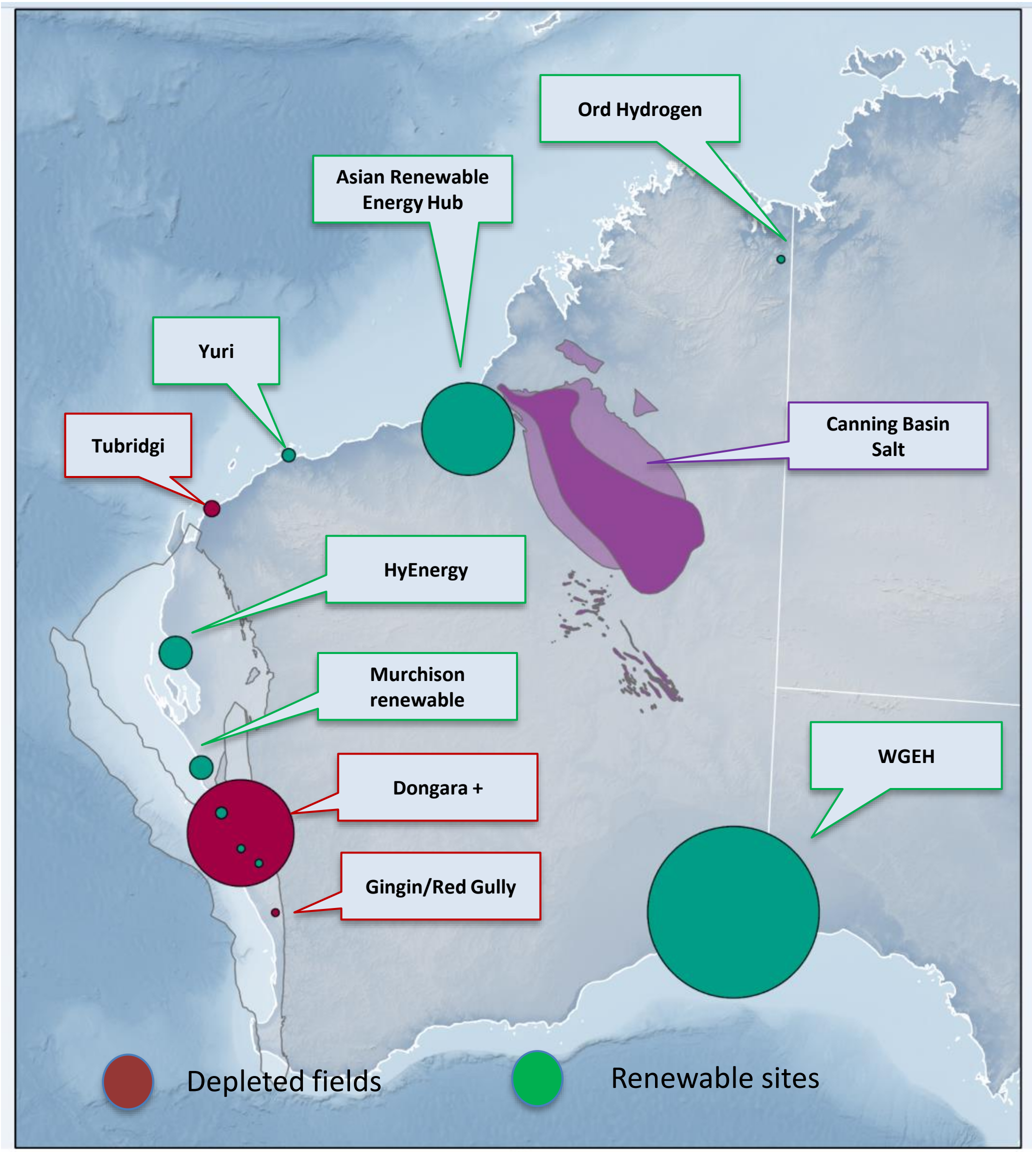


- Numerous renewable sites being considered

- Handful of depleted fields meet screening criteria
- Dominated by Dongara

Location of renewable and potential subsurface storage sites

- Majority of the major renewable energy sites not adjacent to depleted fields
- Exception is the Murchison project and several small renewable sites which are close to North Perth Basin fields
- Asian Renewable Hub is relatively close to Canning Basin salt, although the distances are still large!



Findings

- The global subsurface hydrogen storage industry is at an embryonic stage, but we expect a strong future
- Several globally significant renewable energy sites are currently being considered in WA, all of which have the intent to produce hydrogen
  - Many of these have plans to convert some/all of the hydrogen to ammonia
  - We are not aware of subsurface storage options being considered, but this could change
- The required storage volume has a bearing on the ideal storage method
- Salt caverns
  - Most robust means of storing hydrogen
  - Have been proved to work
  - Can be customised to operational requirements
  - Key issues are location of salt, access to water and disposal of brine
  - Canning Basin salt could provide a good opportunity if environmental concerns can be addressed
- Porous media (depleted gas and oil fields or aquifers)
  - Present several technical challenges and remains unproven.
  - The size of the site is fixed and cannot be customised to operational requirements
  - While we expect the depleted oil and gas fields will present technical challenges, they could still present viable options

Declarations

Terms of Engagement

- This report, any advice, opinions or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by the Client and RISC.

Standard

- Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

Limitations

- The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.
- The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from DRMIRS as well as information in the public domain. The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and key DMIRS staff.
- Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances, regulations that apply to this asset(s). RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.
- We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.
- Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

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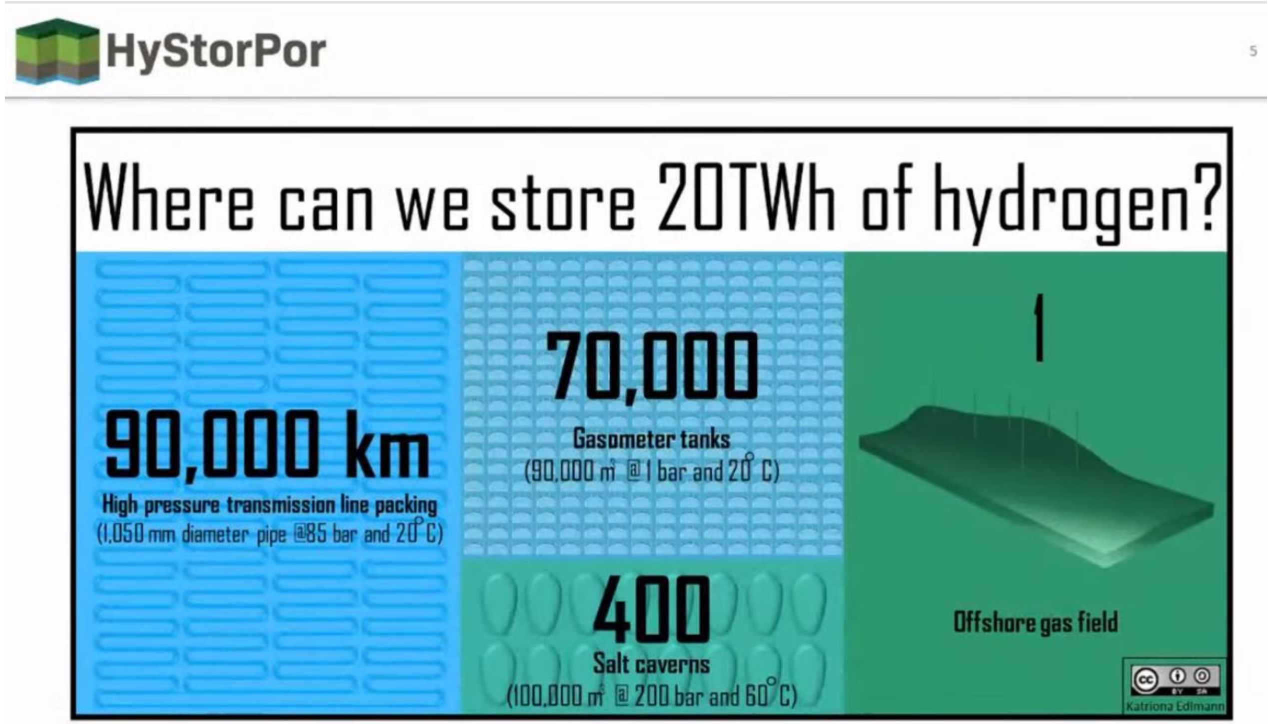
Have we got our sums right?



Katriona Edlmann May 2021

20 TWh = 200 Bscf @ reservoir conditions

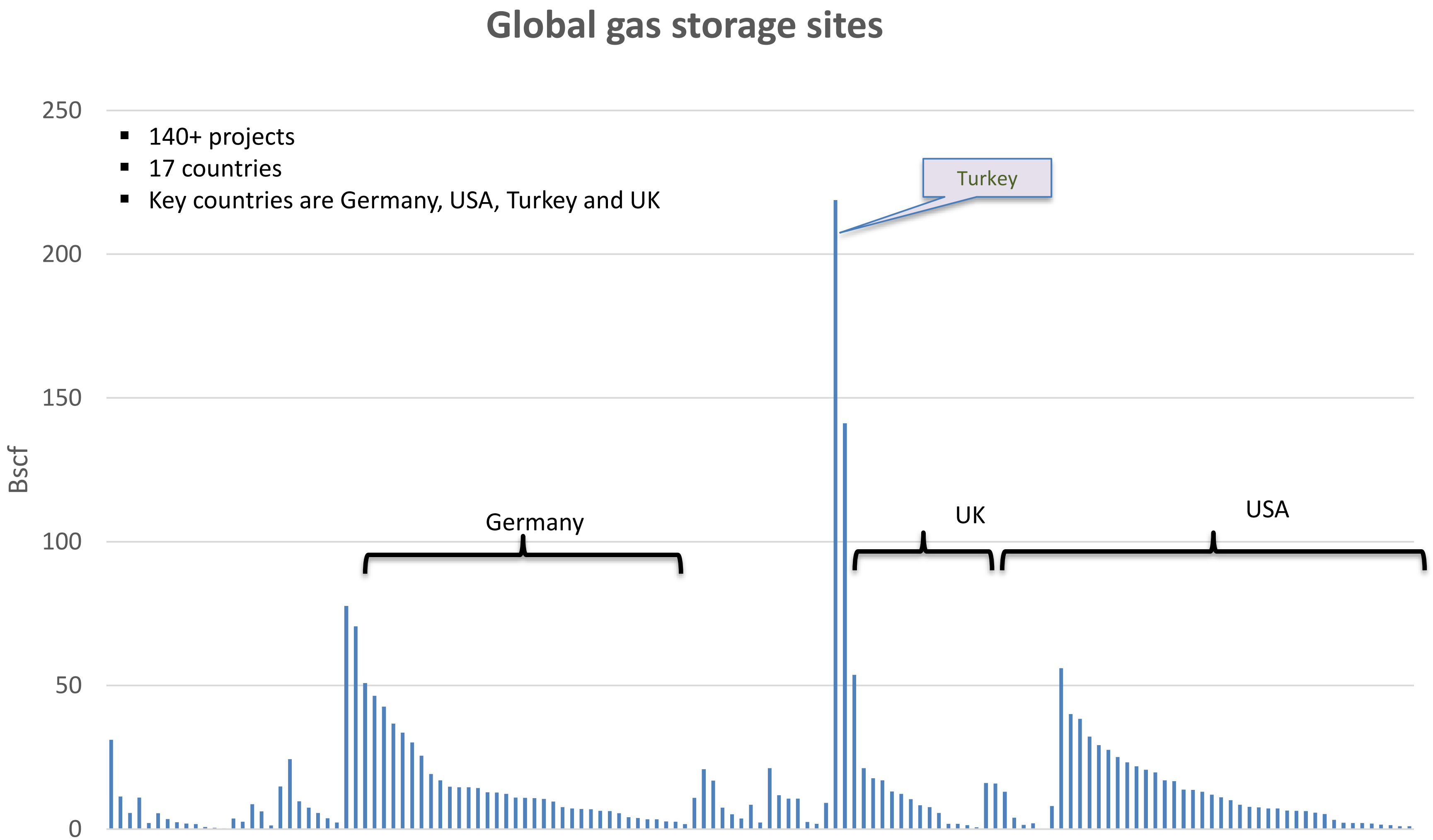
- Assumptions:
  - hydrogen energy density of 141.86 MJ/kg
  - hydrogen density at STP of 0.08988 kg/m
  - FVF of 50
- 1 TWh = 3,600,000,000 MJ = 0.282 billion cubic metres = 9.97 Bscf @ STP
- 20 TWh = 200 Bscf @ STP

Our sums seem to be inline with UK hydrogen storage requirements (222.5 Bscf @ STP)

Findings

- The global subsurface hydrogen storage industry is at an embryonic stage.
  - Subsurface storage of ‘pure’ hydrogen is limited to a handful of caverns manufactured by dissolving the salt by pumping water.
  - There are currently no depleted oil or gas fields used to store ‘pure’ hydrogen
  - There are no examples of aquifers, underground mine sites or tunnels used for hydrogen storage
- Despite the infancy of the industry, there are many published articles related to hydrogen as it will become a major enabler for net zero GHG emission aspirations and targets.
  - The material covers how the hydrogen industry developing, progress and aspirations of various countries, what subsurface sites are being considered, technical challenges and risks
  - There is very limited information directly related to the potential of depleted oil and gas fields in Western Australia
- Several globally significant renewable energy sites are currently being considered in WA all of which have the intent to produce hydrogen, with some of it being converted into ammonia
  - The largest is the Western Green Energy Hub on the South Coast, covering 15,00 km^2 with a plan to produce 50 GW energy
  - The second largest is the Asian Renewable Hub in the East Pilbara. The proposed project will cover an area of 6,500 km^2, cost an estimated $36 B and produce 26 GW.
- **Despite these large projects, RISC estimates that only small volumes of renewable hydrogen will be required to be stored on a transitory basis in the context of depleted oil and gas fields**
  - the maximum storage requirement would be in the order on 10 Bscf, which could be much less in reality
- The small size has a bearing on the ideal storage method. Salt caverns are the most robust means of storing hydrogen and have been proved to work.
  - By far, the focus of hydrogen storage sites globally is in salt caverns, due very low permeability needed to contain hydrogen and solubility in water allowing relatively easy creation
  - The salt acts as an excellent seal, the caverns can be customised to operational requirements, they have a relatively high recovery and a recharge time in the order of days/weeks.
  - The drawback is they need access to large amounts of water in their manufacture and need a means to dispose of the generated brine.
- Storing hydrogen in porous media (depleted gas and oil fields or aquifers) presents several challenges and remains unproven.
  - The physical behaviors and properties of hydrogen are different than natural gas; it is more chemically reactive which may impact reservoir quality, flow behaviour and seal capacity.
  - Hydrogen is also an energy source for subsurface microbial processes which can turn the hydrogen into methane or hydrogen sulphide, e.g. Lobodice, Czech Republic, where approximately half of the hydrogen in stored town gas (45-60% H_2) was transformed into methane or hydrogen sulfide.
  - The size of the site is fixed and cannot be customised to operational requirements (so in all probability will have a relatively low recovery) and a recharge time in the order of months
- We expect the depleted oil and gas fields will have many technical challenges, but Canning Basin salt could provide a good opportunity if environmental concerns can be addressed

…but storing hydrocarbon gas in salt caverns is very common….



General rule seems to be required storage is 10—20% of annual production

UNECE Resource management week 2021

Global:

- 2019 gas demand: ~3,986 bcm[1] (140,764 bcf)
- 2019 gas storage market size: ~483 bcm[2] (17,057 bcf)
- Ca. 10% of demand in storage

EU:

- 2019 gas demand: ~470 bcm[3] (16,598 bcf)
- 2019 gas storage capacity: ~105 bcm[4] (3,708 bcf)
- 2019 storage levels; ~90%[5]
- Ca. 20 – 22% of demand in storage

Hydrogen – OUTLOOK 2030/2050

Key drivers for storage

- Variable production renewable vs demand (peak)
- Heating (seasonal demand)?
- Arbitrage, Import dependency?

EU 2030[6]:

- Hydrogen demand 481 – 665 TWh (5,662 – 7,710 bcf)[7]
- Assumption 10 – 20% storage: ca. 16 bcm – 44 bcm (566 – 1,542 bcf)[7]

EU 2050[6]:

- Hydrogen demand 780 – 2,251 TWh (9,182 – 26,498 bcf)[7]
- Assumption 10 – 20% storage: ca. 26 bcm – 150 bcm (918 – 5,297 bcf)[7]

bcm = billion cubic metres
bcf = billion cubic feet

1) IEA 2020: Natural Gas Information: Overview
2) Grand View Research 2020: Natural Gas Storage Market Size, Share & Trends Analysis Report
3) Statista 2020: Natural gas consumption in the European Union from 1998 to 2019
4) GIE gas storage database (dec. 2018)
5) EC –DG Energy 2019: Quarterly Report Energy on European Gas Markets
6) FCH-JU 2019: Hydrogen Roadmap Europe
7) Assumes Hydrogen energy density of 120 MJ/kg and 0.08988 kg/cubic m – no compression

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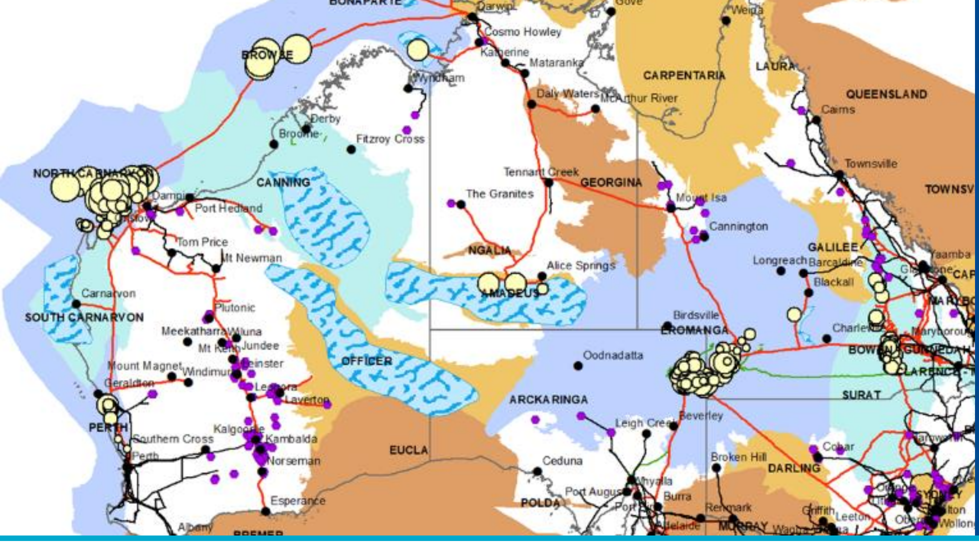
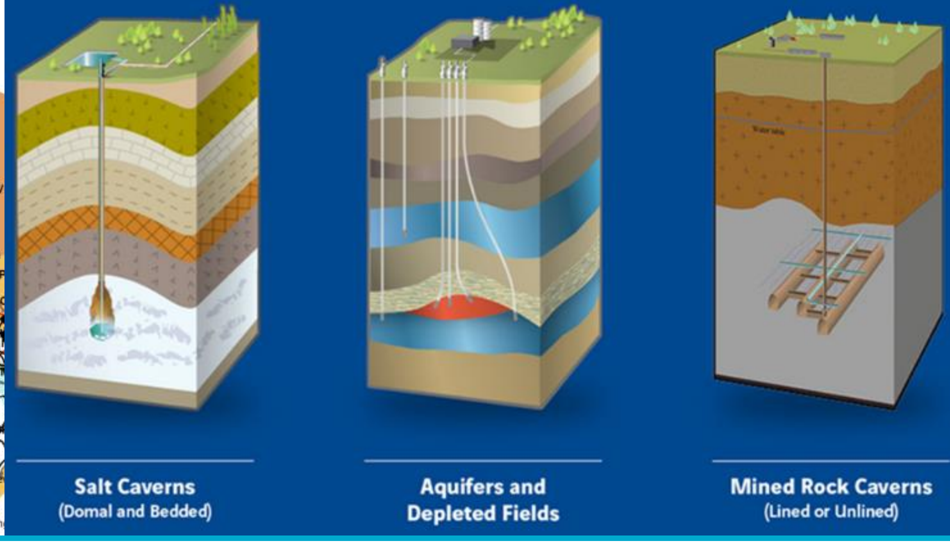




Underground Storage of Hydrogen: Mapping out the Options for Australia

K. Michael, J. Ennis-King, J. Strand, R. Sander, C. Green

21st July 2021

FUTURE FUELS CRC

CSIRO

Project background

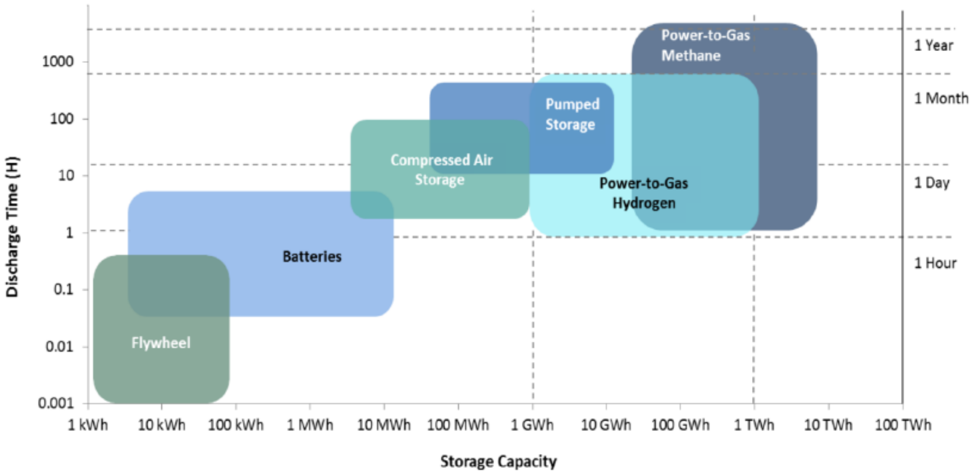
Widespread adoption of hydrogen in Australia as an energy carrier will require storage options to buffer the fluctuations in supply and demand, both for domestic use and for export.

Once the scale of storage at a site exceeds tens of tonnes, underground hydrogen storage (UHS) is the preferred option for reasons of both cost and safety.

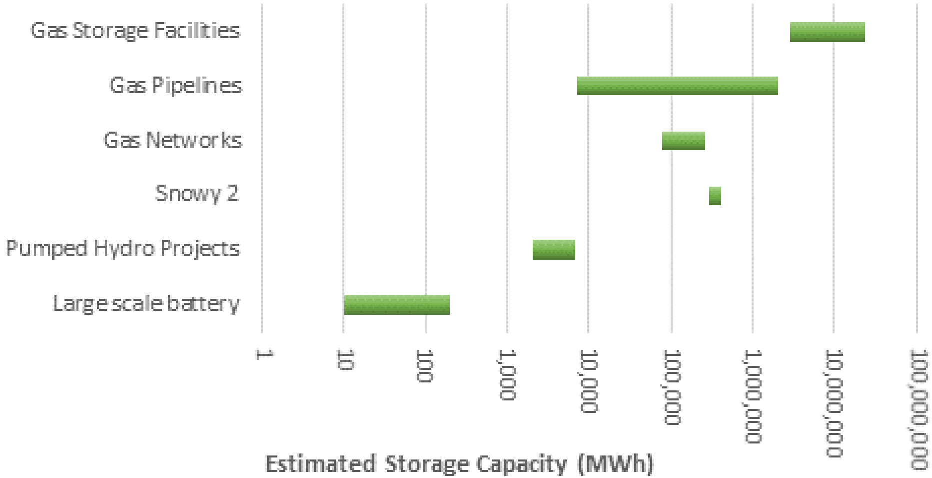
The objectives of the project were to:

- Review global UHS experience and technologies
- Identify the most suitable options for UHS in Australia
- Estimate the scale of prospective storage capacity on a regional scale

Characteristics of different energy storage technologies



(European Commission, 2017)



Estimated energy storage capacity of natural gas facilities and pipeline in comparison to other storage options in Australia (www.energynetworks.com.au/).

Global state of UHS

- H_2 is largely produced from steam methane reformation and used in chemical industries/refining
- Future initiatives are often looking at successively adding H_2 to the existing gas network before renewable energy production has sufficient market penetration.
- Salt caverns are currently the only option used commercially for pure H_2 storage
- UHS in porous formations is limited to:
  - 'Town gas' (H_2, CH_4, CO, etc.)
  - Pilot projects in Austria and Argentina* (H_2/CH_4 blending in gas fields)
- Research is focussed on UHS in gas fields & aquifers
  - Geochemical reactions
  - Microbial effects
  - Loss of H_2 to reservoir due to diffusion & leakage

	Type	% H_2	Depth (m)	Volume (m^3)	Capacity (GWh/PJ)
Teesside, UK	Salt cavern	85	400	3 x 70,000	35/0.13
Spindletop, Texas	Salt cavern	95	1500	906,000	278/1
Clemens Dome, Texas	Salt cavern	95	850	580,000	85/0.3
Moss Bluff, Texas	Salt cavern	95	1200	566,000	80/0.29
Beynes, France	Aquifer	50	430		
Ketzin, Germany	Aquifer	62			
Lobodice, Czech	Aquifer	50	430		
Bad Lauchstaedt, Germany	Salt cavern		820		
Kiel, Germany	Salt cavern	60 – 64	1330	32,000	
Diadema, Argentina Hychico *	Natural Gas	10	850	750,000	
Underground Sun Storage, Voecklerbruck, Austria*	Natural Gas	10	1000		

Panfilov, 2016; and data from company websites

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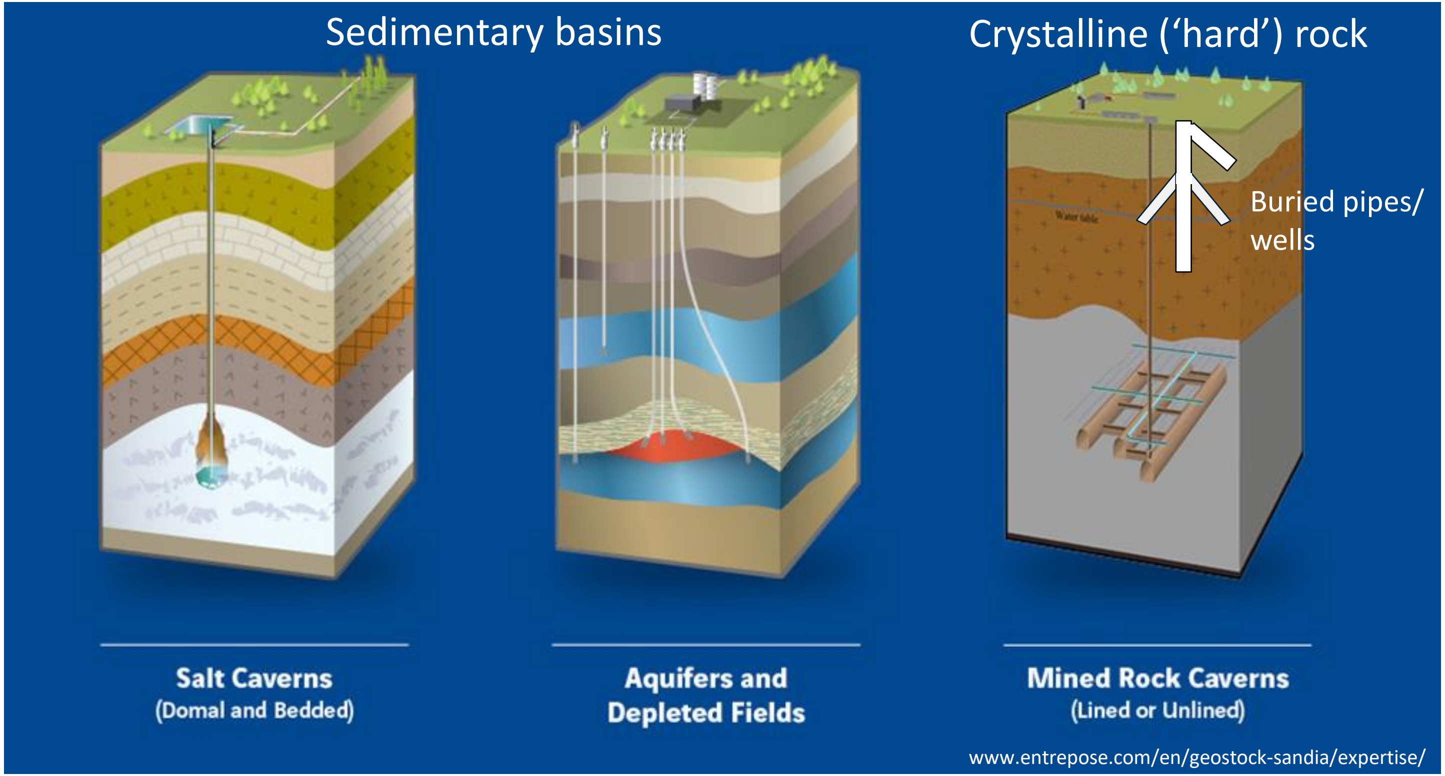
Analogue to underground gas storage (UGS)

- Approximately a total of 670 UGS facilities exits globally:
  - Salt caverns: 104
  - Depleted fields: 492
  - Aquifers: 75
- Most UGS sites are in North America (450) & Europe (142)
- Australia has 9 UGS facilities, all in depleted gas fields
- Moomba is the biggest Australian UGS site with a gas storage capacity of 85 PJ, which is volumetrically equivalent to 23 PJ H_2 storage capacity

Storage facility	Operator	State	Depth (m)	Inj. Capacity (TJ/d)	Withdrawal (TJ/d)	Storage capacity (PJ)	UHS capacity	
							(PJ)	(kt)
Ballera Chookoo	Santos	Qld		20	40	11	3	25
Iona	Lochard Energy	Vic	1300	155	500	23.5	6.3	53
Moomba	Santos	SA	2400	110	30-120	85	23	191
Newstead	Armour Energy	Qld	1450	8	7.5	2.0	0.5	4.4
Roma	GLNG	Qld	1000	105	58	54	15	122
Silver Springs	AGL	Qld	1900	16	20	46	12	104
Newcastle LNG	AGL	NSW		14	120	1.5	0.4	3.4
Tubridgi	AGIG	WA	550	90	60	57	15	128
Mondarra	APA	WA	2700	70	150	15	4	34

Options for UHS



Decreasing TRL level

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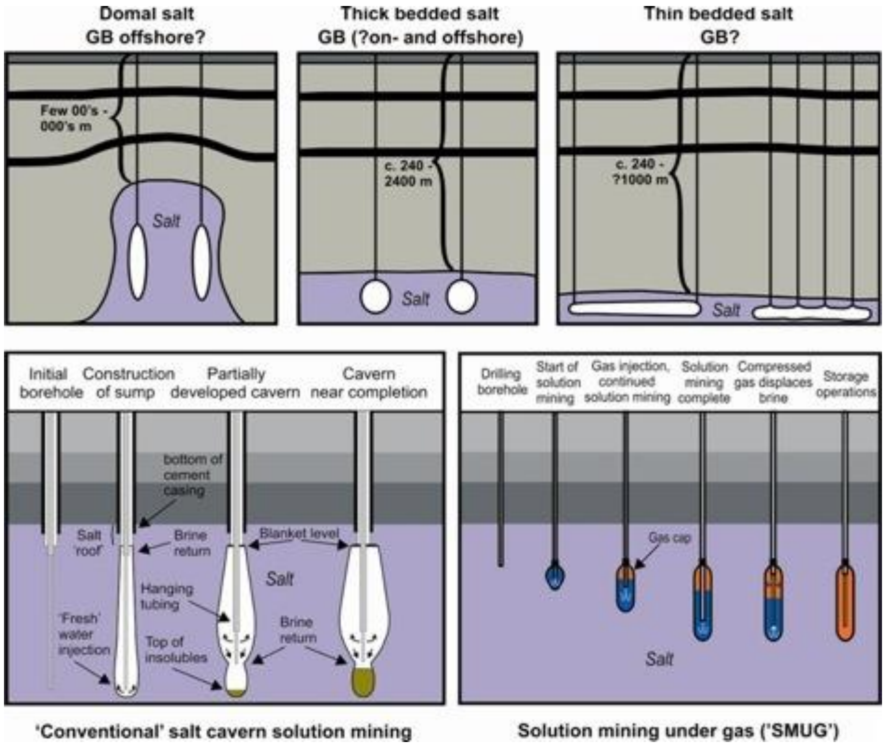
UHS options – salt caverns



- Salt caverns are currently the only UHS option used commercially.
- Good containment and injectivity/producibility
- The capacity of salt caverns is determined by geo-mechanical safety aspects, and parameters to be considered are salt thicknesses in the hanging wall and foot wall & cavern shape.
  - Domal structures: up to 210 GWh,
  - Bedded salt: 65 and 160 GWh
- Largest UHS facility in the world, Spindletop in Texas, has a working volume equivalent to approximately 277.8 GWh (1PJ).
- Brine disposal environmental issues & comparatively higher development costs compared to storage in porous reservoirs.
- Lack of salt cavern storage experience in Australia
- Plans for CSG-to-LNG projects in the 500 m thick salt at approximately 2000 m depth in the Adavale Basin (QLD).

Options for creating caverns in salt formations (Nathan, 2013; www.theengineer.co.uk/ underground-revolution-hydrogen-storage-for-flexible-generation/)

UHS options – porous formations (hydrocarbon fields & aquifers)

- Depleted gas fields were used historically for the storage of 'town gas' (CH_4, H_2, CO,…).
- Recent pilot projects blending H_2 with CH_4 in natural gas storage sites in Austria and Argentina.
- Lower density (8- 10 times) and viscosity of H_2 relative to CH_4 would result in 2.4 to 2.7 times higher withdrawal rates, which partly compensate for the lower energy content of H_2 (3-4 times lower than CH_4), resulting in an energy throughput of 0.7 to 0.8 times that of CH_4.
- Issues include:
  - Hydrogen losses due to diffusion or dissolution in water, or mixing with cushion gas
  - Contamination with reservoir gas or due to geochemical and microbiological effects, i.e. H_2S

Aquifer versus gas reservoir storage

Pros	Cons
• **No potential for contamination with reservoir gas,**	• Need for finding a structural closure with a competent seal,
• **Less potential for microbial activity due to the lack of a carbon source,**	• Additional characterisation, data collection and analysis requirements.
• **No conflict with timing of gas production**	• Potential conflicts with groundwater

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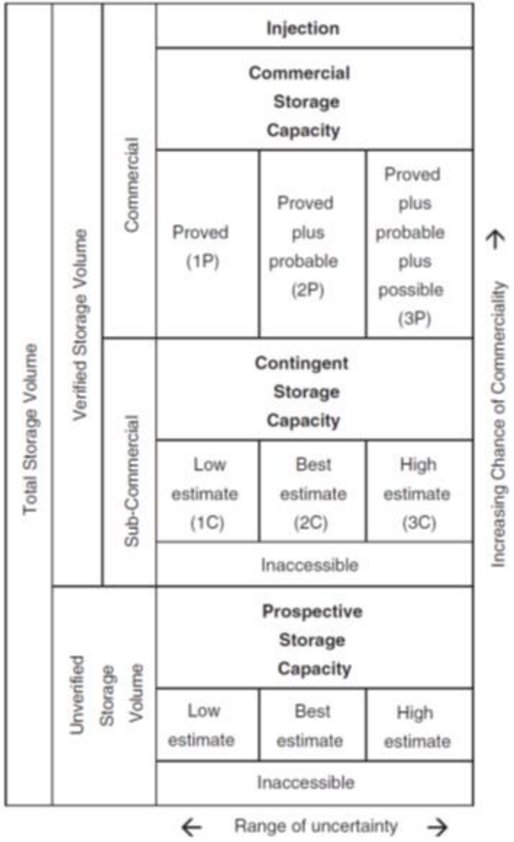
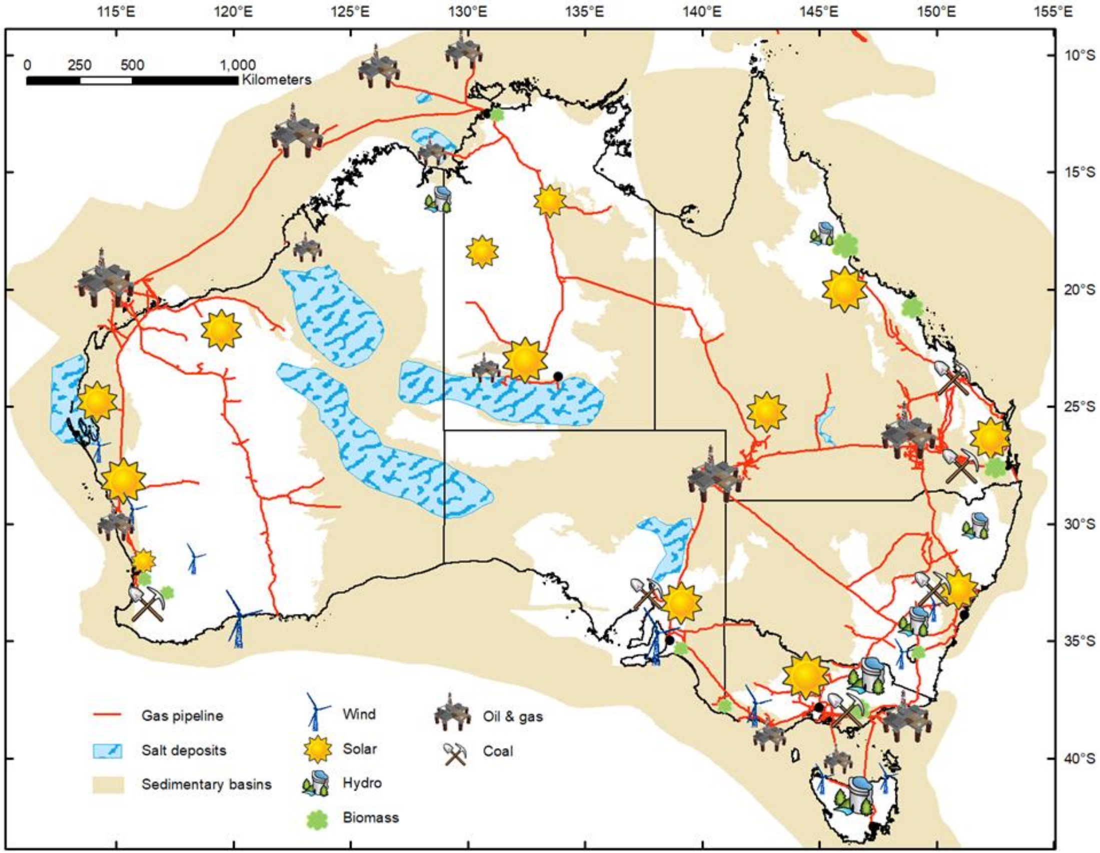
Australian UHS assessment

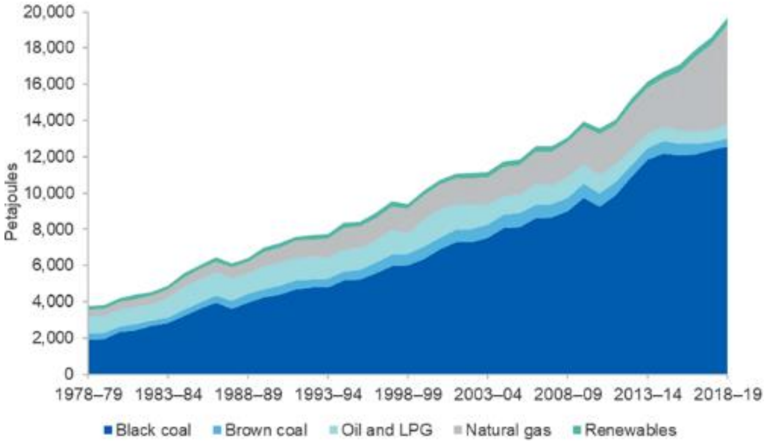
- Focus is on prospective storage capacity
- Important to emphasise that it's a technical geological assessment
  - Doesn't imply social or environmental acceptability
  - Doesn't imply commerciality in any specific location
  - Prelude to a much more detailed phase of site work.
- Key outcome is that the scale of prospective storage is much greater than potential demand for UHS – so only a few sites would be needed in each region.



Energy landscape in Australia



Annual energy production
(incl. 80% export)



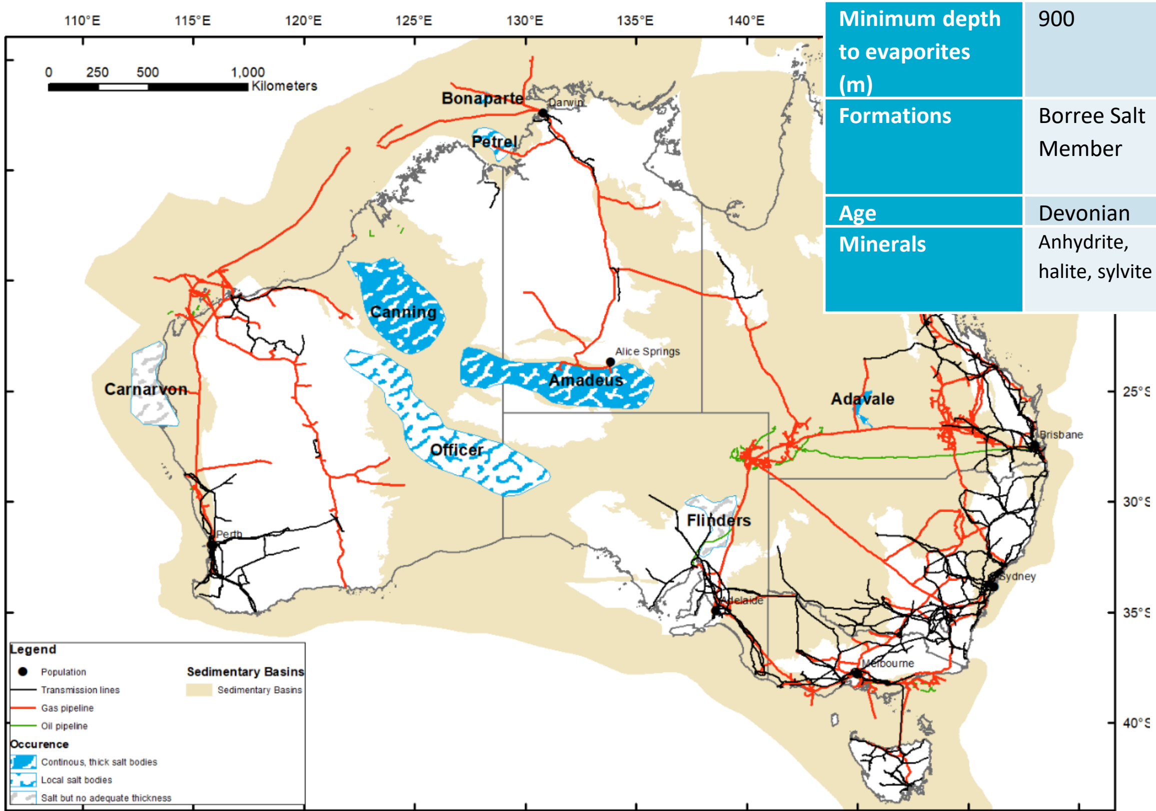
Storage capacity requirements for different hydrogen usage

Hydrogen usage	Storage capacity requirement in PJ (kt H_2)	
	Australia total	Per project
Stabilisation of electricity network[1]	1.26 – 1.62 (10 – 13)	0.00036 – 1.26 (0.003 – 20)
Security of gas network[2]	~300 (2,420)	0.25 - 25 (2 – 200)
Export[3]	~300 (2,420)	1.25 - 12.5 (10 – 100)
Total	~600 (4,840)	

[1]based on AEMO 'neutral' scenario requiring 350-450 GWh energy storage by 2040 and 50% conversion efficiency; site storage ranges from 100 MWh (current battery storage at wind/solar farms) to 350 GWh (Snowy 2.0)
[2]based on gas storage capacity in existing UGS facilities in 2020.
[3]assuming 1 week storage of 2019 annual energy export (15,900 PJ) and weekly hydrogen production from large-scale projects of 10 to 100 kt H_2.

Storage in salt caverns

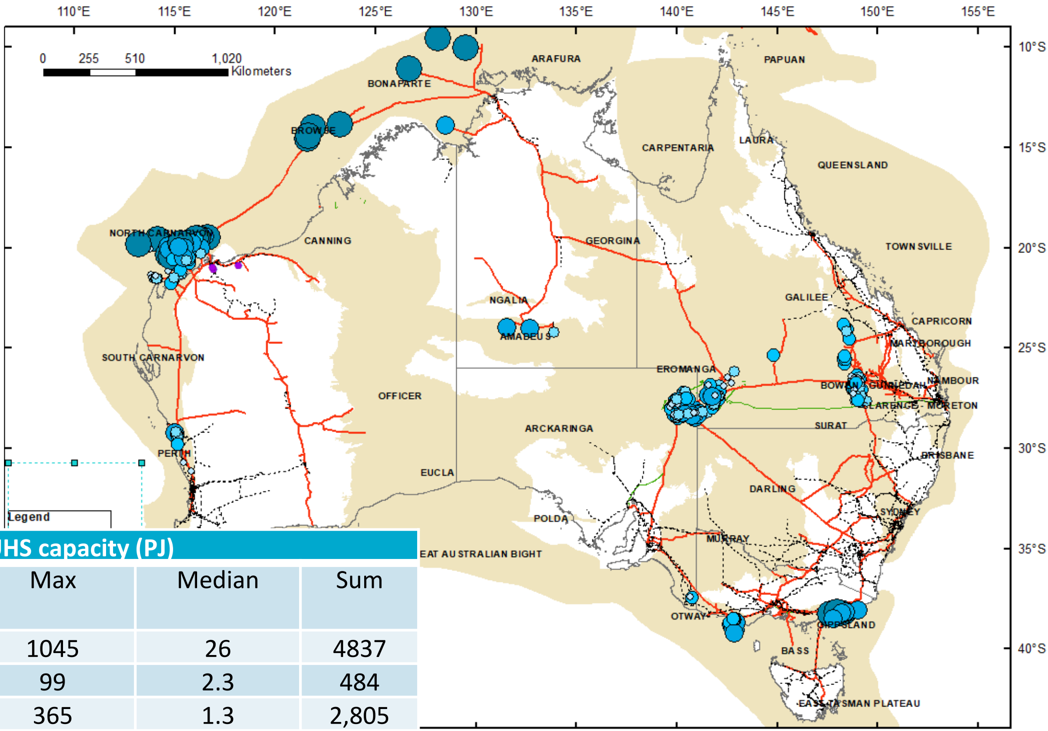
Name	Adavale	Amadeus	Canning	Carnarvon	Officer
Basin area (km^2)	60 000	140 000	430 000	300 000	410 000
Area of evaporites (km^2)	8 000	120 000	200 000	1 300	100 000
Sediment thickness (km)	5	14	12	7	10
Evaporite thickness (m)	900	225*	800	37	70*
Minimum depth to evaporites (m)	900	surface	688	1130	surface
Formations	Borree Salt Member	Gillen Fm (Bitter Springs Gp)	Carribuddy Gp (Worral Fm)	Yaringa Salt Member (Dirk Hartog Fm)	Browne Fm (Buldya Gp)
Age	Devonian	Tonian	Ordovician	Silurian	Tonian
Minerals	Anhydrite, halite, sylvite	Halite, gypsum, anhydrite, dolomite	Halite, dolomite, anhydrite, barite	Halite, anhydrite, dolomitic anhydrite, sylvite	Gypsum, anhydrite



Storage in gas fields – capacity estimation based on gas reserves

E_{H2} (PJ) = 0.27 * E_{CH4}

= 0.27* V_{CH4} (m^3) * 0.0732 kg/m^3 * 53.4*10^{-9} PJ/kg



Basin	Number of gas fields		UHS capacity (PJ)			
	Total	>0.25 PJ	Min	Max	Median	Sum
Gippsland	41	39	0.1	1045	26	4837
Otway	37	31	0.0002	99	2.3	484
Eromanga	258	195	0.00002	365	1.3	2,805
Bowen- Surat	115	79	0.0001	29	0.7	316
Bonaparte-Browse	7	6	0.2	1800	823	5,507
Carnarvon	116	101	0.02	3748	7.9	23,710
North Perth	20	14	0.03	135	1.1	205
Amadeus	3	3	2.4	80		131
Total	598	**460**			1.8	**37,996**

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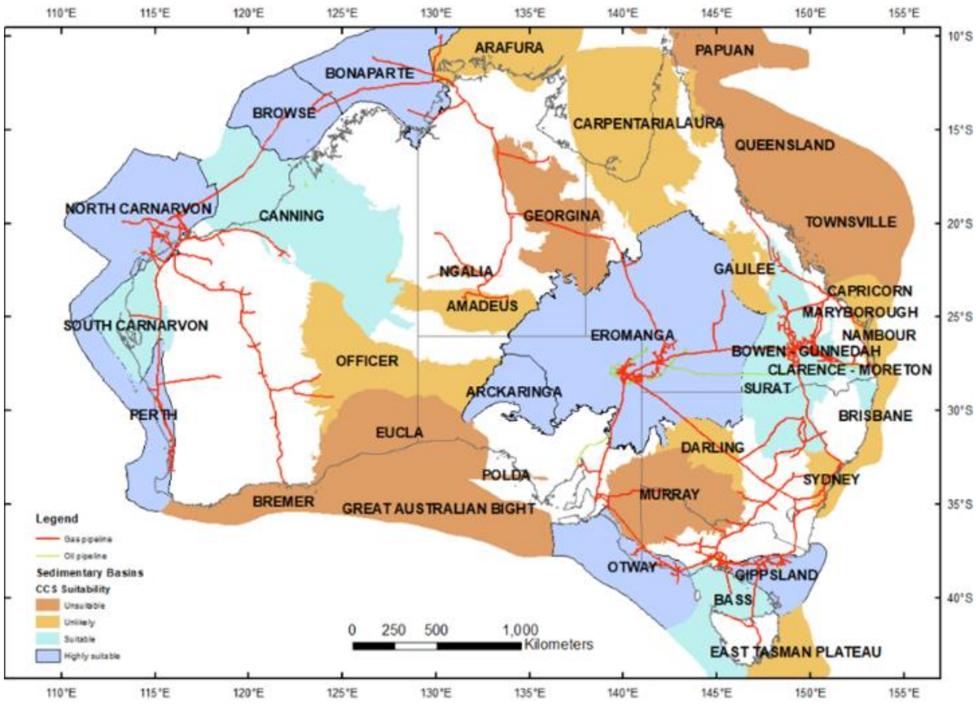
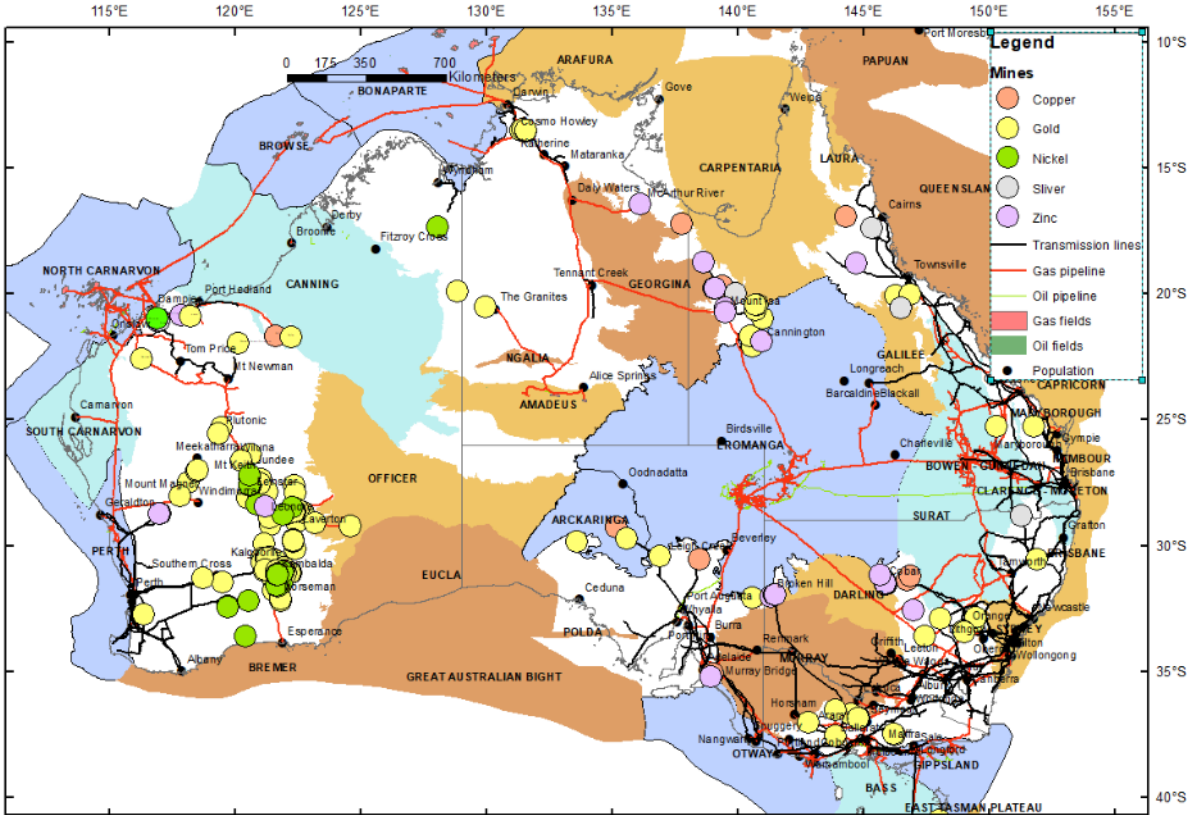
Storage in aquifers

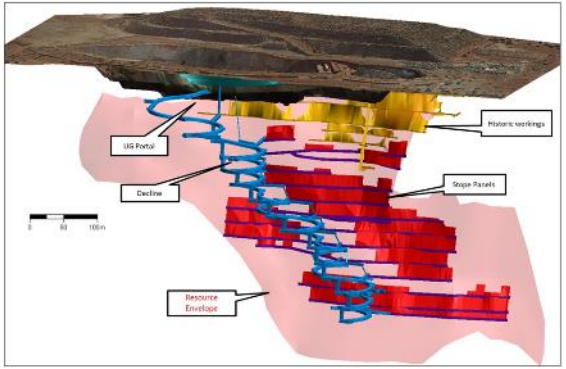


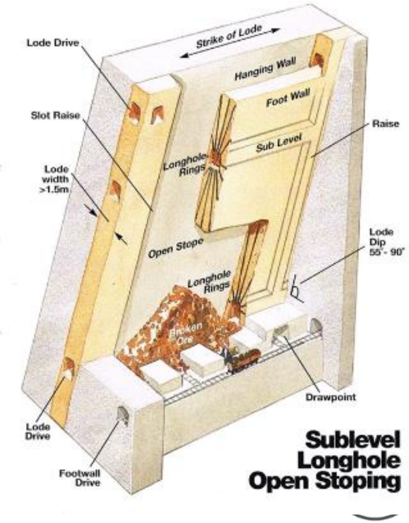
Basin	CO_2 Storage Capacity (Gt)			Suitability score
	P10	P50	P90	
Gippsland (offshore)	30.1	51.0	80.3	0.91
Gippsland (onshore)	0.7	1.0	1.4	0.57
Bass	12.7	19.1	26.1	0.61
Torquay	1.6	22	2.9	0.56
Otway (East)	8.4	14.5	21.0	0.64
Otway (West)	4.5	11.0	23.7	0.58
Eromanga (SA)	11.6	26.8	52.5	0.80
Cooper	4.1	7.9	14.7	0.68
Bowen	1.6	3.3	5.9	0.66
Surat	6.1	10.3	16.1	0.59
Sydney	0.4	0.8	1.6	0.50
Darling	2.6	7.2	16.4	0.58
Gunnedah	0.4	0.8	1.6	0.42
Galilee	7.5	14.0	21.9	0.62
Clarence-Morton	2.9	5.5	10.2	0.51
Denison Trough	1.7	3.0	4.9	0.59
Roma Shelf	0.1	0.1	0.2	0.64
Bonaparte (NT	32.2	55.3	88.0	0.62
Browse	7.0	11.3	16.3	0.73
Canning (onshore)	16.5	33.3	59.8	0.61
Canning (offshore	23.5	37.7	56.0	0.55
Carnarvon (North)	25.5	48.5	89.3	0.78
Carnarvon (South)	11.1	22.8	40.1	0.50
Vlaming	0.2	0.3	0.4	0.64
North Perth (onshore)	1.4	2.9	5.3	0.63
Total	226.6	417.0	701.9	

- Based largely on the assessment of CO_2 aquifer storage in Australian basins
- Volumetrically equivalent **H_2 storage capacity would be orders of magnitude less** because UHS requires structural traps, and their volumes/occurrences are not well mapped.

Storage in engineered mines



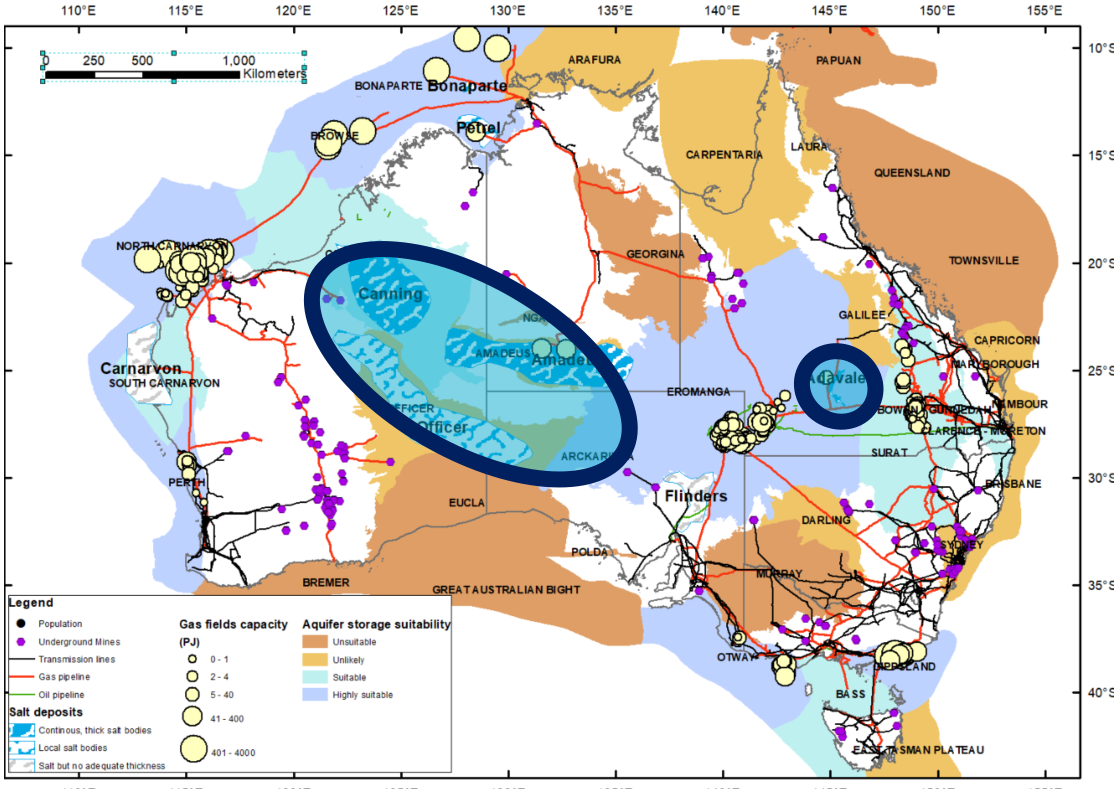




Underground mines may provide storage options where sedimentary basin storage options are not available

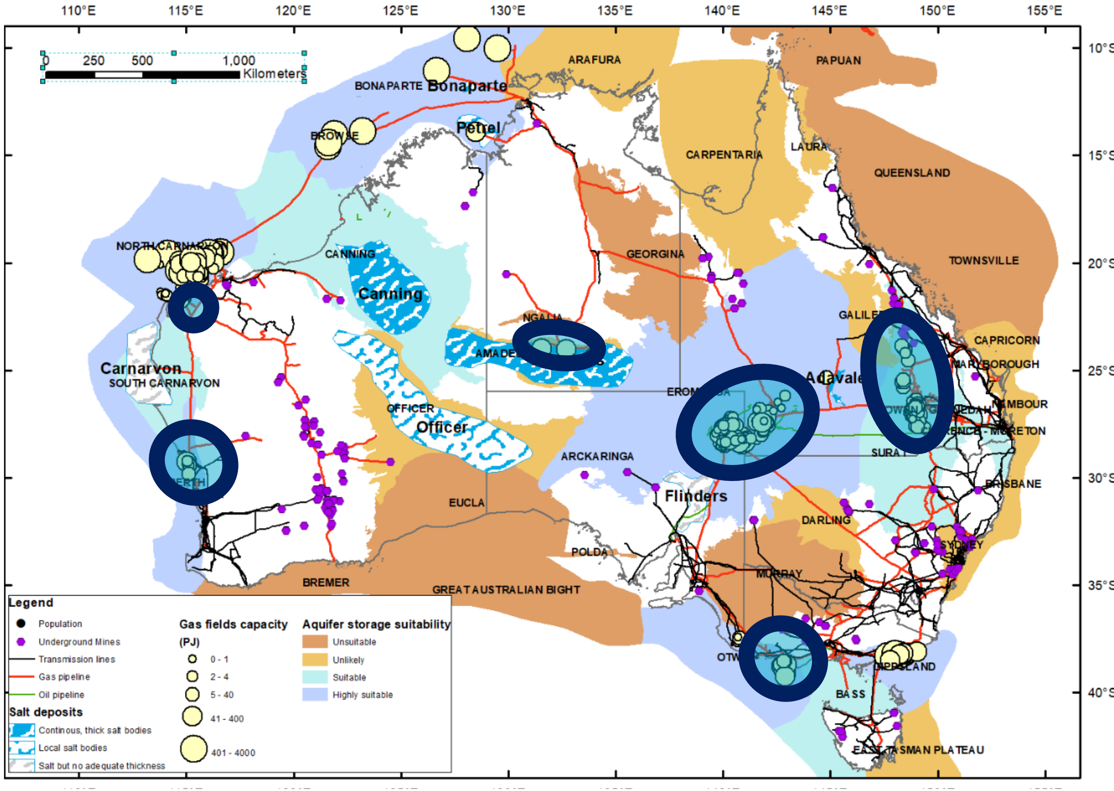
Conclusions- UHS options in Australia

- Various Australian basins contain salt deposits suitable for the creation of storage caverns:
  - Canning Basin
  - Adavale Basin
  - Amadeus Basin
  - (Officer Basin)
- Not necessarily in areas of hydrogen production/processing
- No previous experience with salt cavern storage in Australia



Conclusions- UHS options in Australia

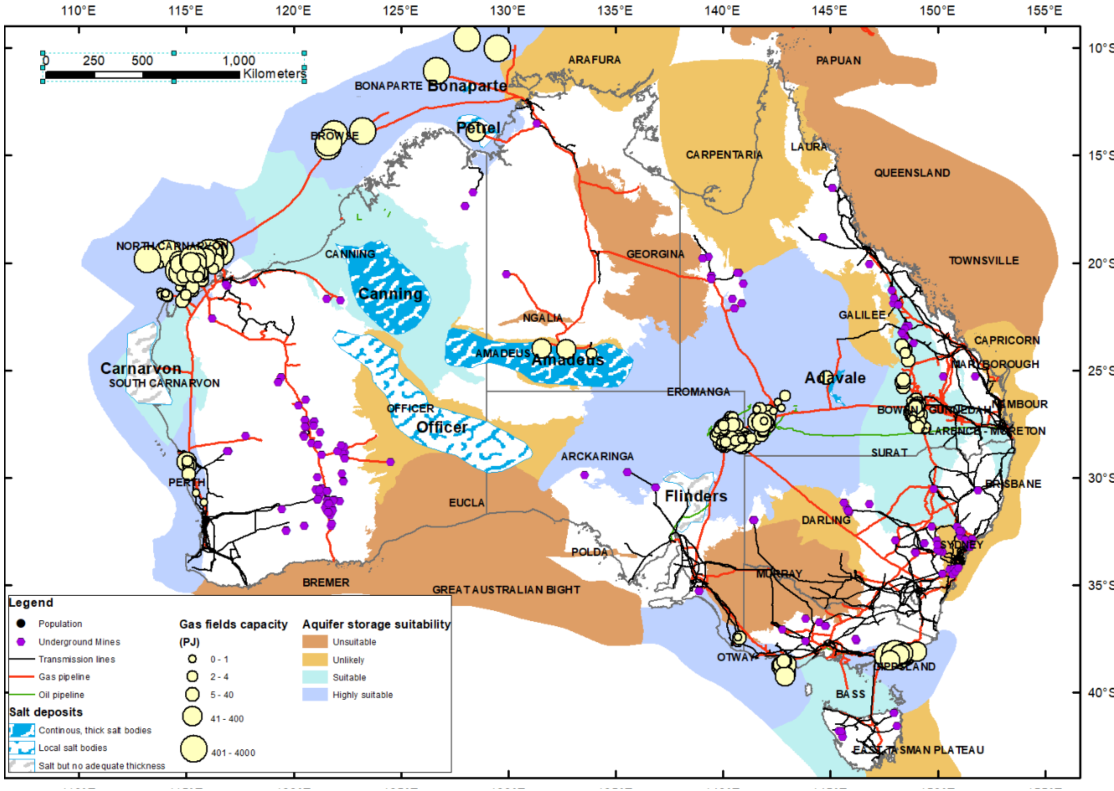
- Depleted gas fields appear to be the most widely available UHS option in Australia with more than sufficient prospective capacity
- Onshore gas fields in potential hydrogen hub areas include:
  - North Perth Basin (200 PJ)
  - Otway Basin (40 PJ)
  - Eromanga Basin (2,800 PJ)
  - Bowen/Surat Basin (300 PJ)
  - Amadeus Basin (130 PJ)
- The total prospective UHS capacity is 38,000 PJ (~310,000 kt H_2)
- Total energy production in Australia is ~ 20,000 PJ, Moomba UGS: ~ 23 PJ



Conclusions- UHS options in Australia

- The main demand for UHS will probably be for the purpose of export or H_2 replacing domestic natural gas usage
- Possibly niche opportunities for electricity grid stabilisation if other energy storage (e.g. pumped hydro, batteries) infeasible
- Alternative UHS options to be considered (if salt not available and gas field storage proves technically challenging) are:
  - Aquifers
  - Hard rock mine shafts (lined)
  - Buried pipes

Decreasing capacity



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Future work

Implementing UHS in salt caverns Australia requires:

- a more detailed mapping and characterisation of known salt deposits,
- exploration for new salt deposits,
- UHS pilot/demonstration in Australian salt caverns

For gas fields, the actual capacity, or dynamic storage capacity, would need to be confirmed, initially through reservoir simulations, but ultimately by performing pilot hydrogen injection and production experiments. Specifical aspects to be tested include:

- Amount of cushion gas needed, mixing with residual hydrocarbons
- Interaction of hydrogen with seal – capillary pressure (containment), diffusion, reaction
- Interaction of hydrogen with reservoir – relative permeability, wettability, geochemistry

Future work

Modelling

- Accurate equations of state for hydrogen-gas mixtures and brine
- Code comparison for simulating UHS in depleted fields and aquifers
- Coupling with microbiology and geochemistry

Microbiological effects on stored hydrogen

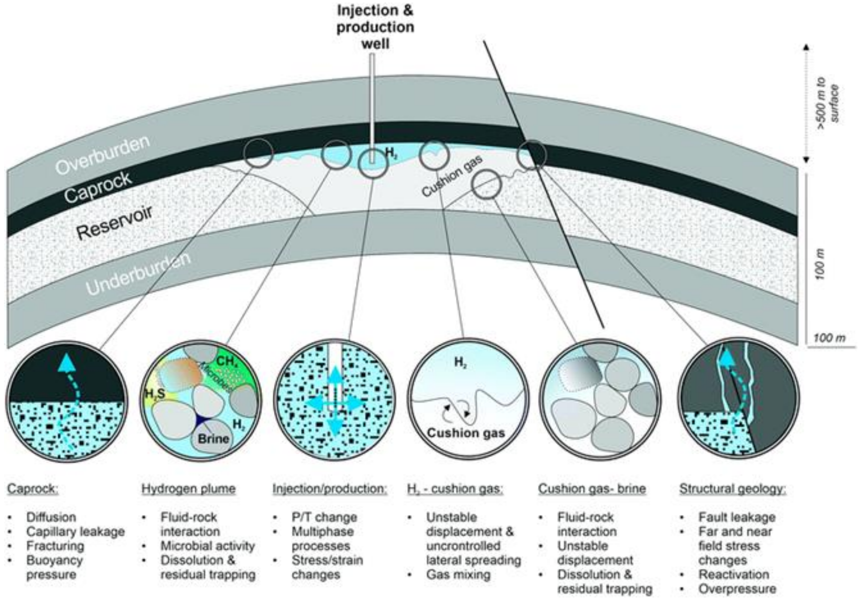
- Characterisation of microbes, and lab studies of effects on hydrogen-gas mixtures
- Calibration of theoretical models for microbial effects on hydrogen

Techno-economics

- site-specific comparisons of the total costs of supply, transport and storage
- Compare salt caverns, depleted gas fields and aquifers for specific conditions

Thank you

SECURE LARGE-SCALE GEOLOGICAL STORAGE OF HYDROGEN: The HyStorPor Project



https://doi.org/10.1039/D0EE03536J

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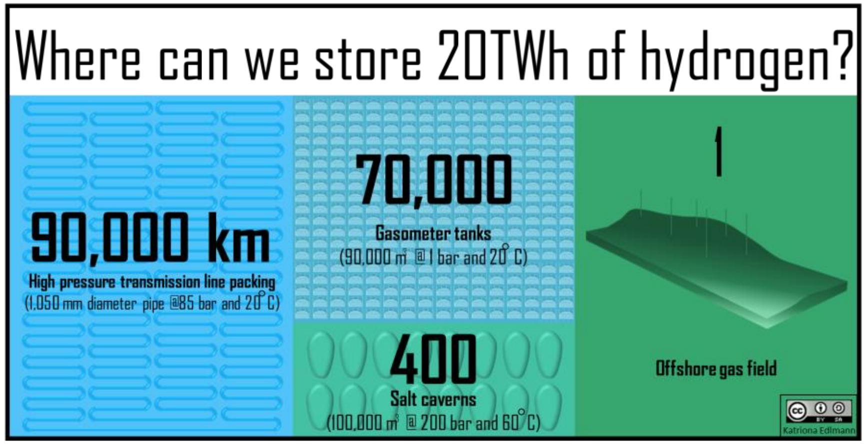
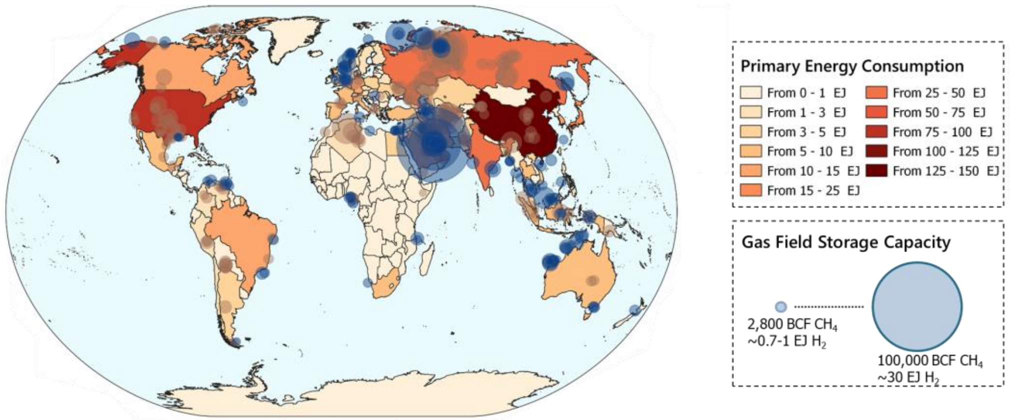
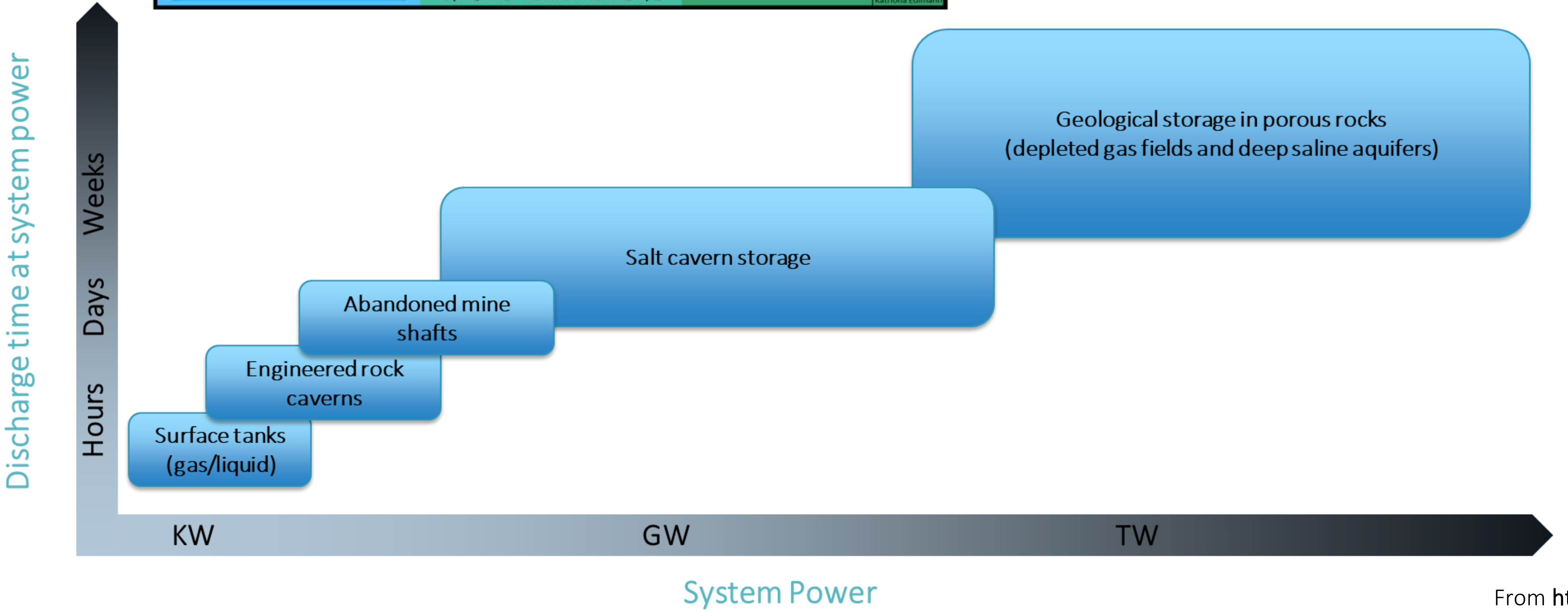
EP/S027815/1

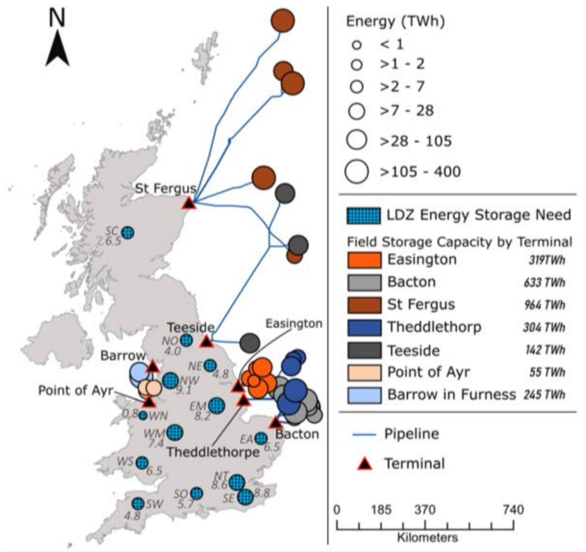
Scales and deliverability of hydrogen storage





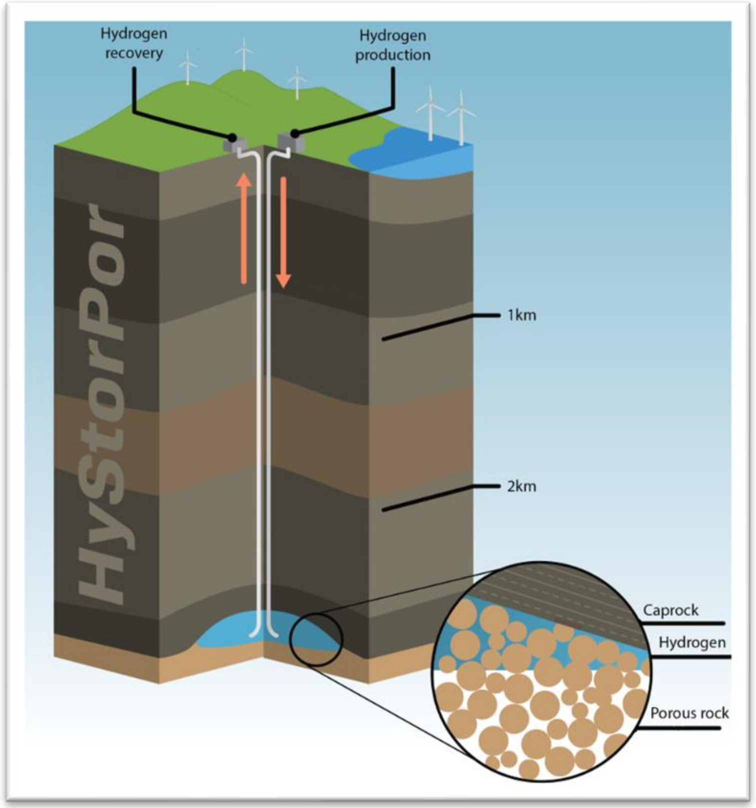
From https://doi.org/10.1021/acsenergylett.1c00845 (hssnpr@ed.ac.uk)





From https://doi.org/10.1016/j.apenergy.2020.116348 (julien.moulicastillo@ed.ac.uk)

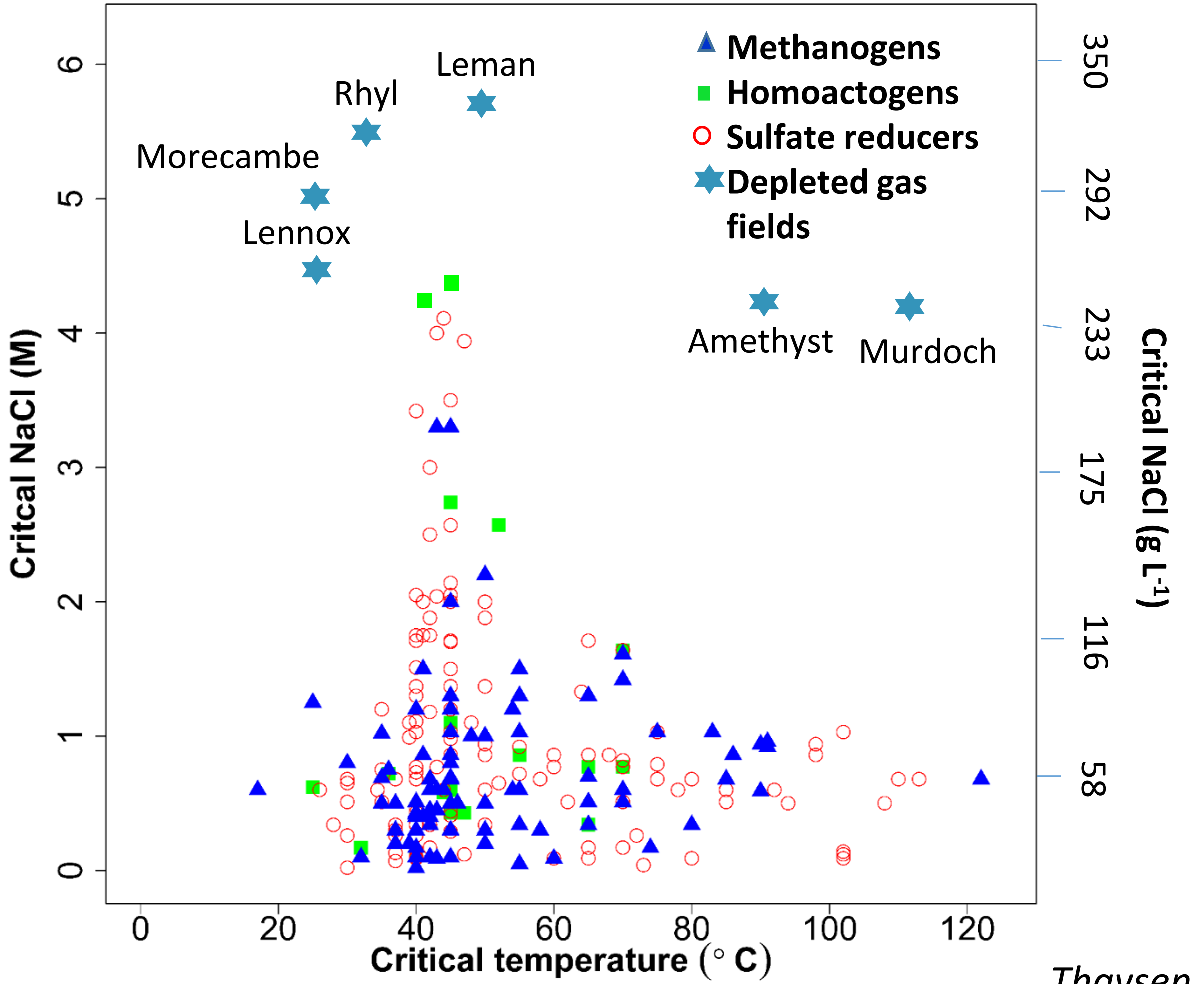
HyStorPor Goals: Fundamental understandings



- To identify if **biological and chemical reactions** between the rock, fluids, cushion gas and hydrogen could compromise storage.
- To determine what **flow processes** will influence hydrogen migration and trapping during injection and withdrawal.
- **Reservoir simulations to estimate what volumes of hydrogen can be stored and recovered** from storage sites of varying scales.
- To **clarify what citizens and opinion shapers think about hydrogen storage.**

https://blogs.ed.ac.uk/hystorpor/

Microbial reactions: life limits for site screening



The most important factors controlling growth are **salinity** and **temperature.**

Storing hydrogen at temperatures >122 °C and >4.4 M NaCl eqv salinity reduces the risk of H_2 loss

6 out of the 47 fields studied are unfavourable to microbial growth

*Limitation of our analysis is that the data is based on **cultivated species and studies on the microbial ecology** – not directly from hydrocarbon reservoirs.*

Thaysen et al. https://eartharxiv.org/repository/view/1799/ *(eike.thaysen@ed.ac.uk)*

Geochemical reactions: no significant reactions

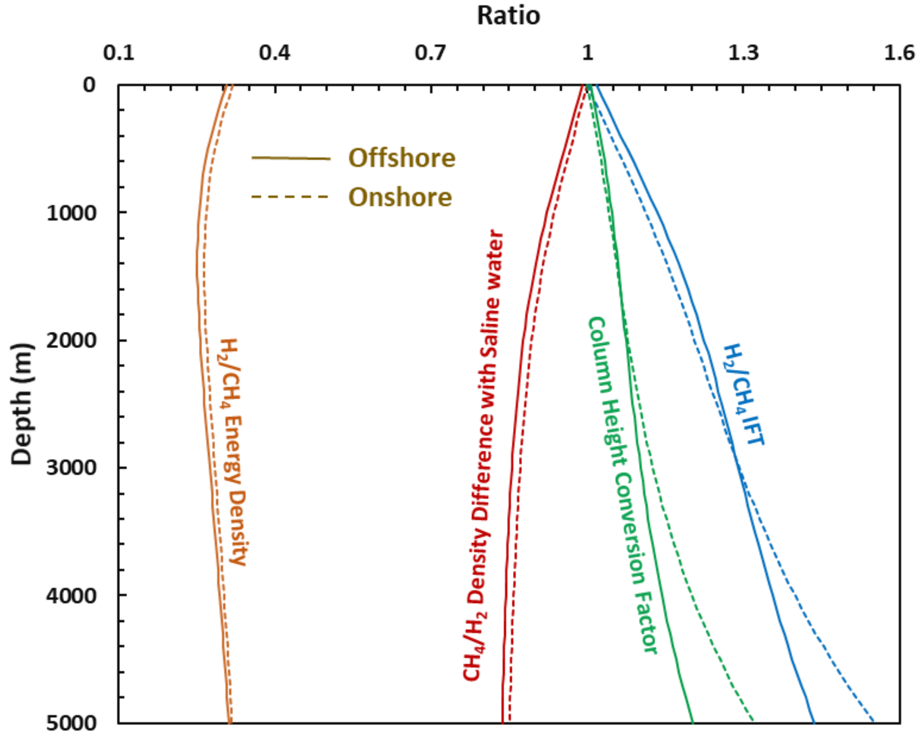
- Hydrogen batch reaction vessels: Pressures of 60 MPa and temperatures up to 80oC
- We have tested over 200 different samples from a wide range of sandstones, caprocks and well cements.
- Results show there is **minimal** geochemical reactivity with hydrogen under storage site conditions

Ali Hassanpouryouzband (hssnpr@ed.ac.uk)

Hydrogen caprock sealing

- Column heights reflect the sealing capacity of any caprock.
- Column height conversion factor calculated to convert known natural gas column heights to hydrogen column heights.
- Hydrogen can be stored at a higher pressure in the reservoir than methane.

$$\Psi_{\mathrm{CH_4/H_2}} = \overbrace{\frac{\Delta\rho_{\mathrm{CH_4/water}}}{\Delta\rho_{\mathrm{H_2/water}}}}^{\textit{Density}} \overbrace{\frac{\gamma_{\mathrm{H_2/water}}}{\gamma_{\mathrm{CH_4/water}}}}^{\textit{IFT ratio}} \overbrace{\frac{\cos\theta_{H_2/\mathrm{water}}}{\cos\theta_{\mathrm{CH_4/water}}}}^{\textit{Wettability}}$$

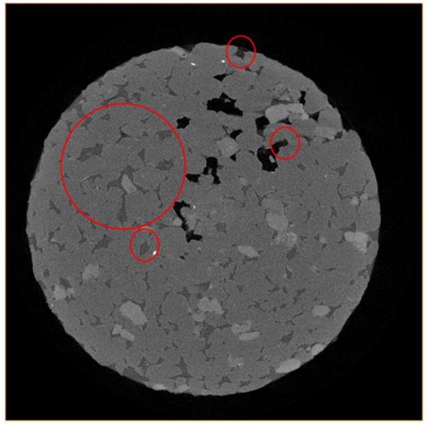


Ali Hassanpouryouzband (hssnpr@ed.ac.uk) https://pubs.acs.org/doi/10.1021/acsenergylett.1c00845

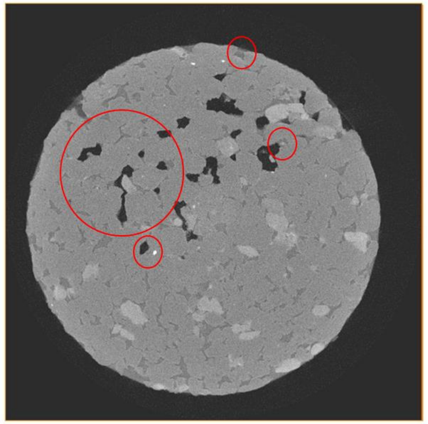
Hydrogen flow visualisation

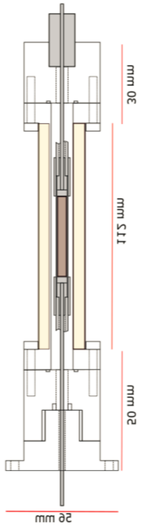
- Bespoke 5mm diameter X-ray transparent hydrogen flow cell.
- Clashach sandstone.
- Imaging experiments to determine:
  - capillary pressure at different saturations.
  - relative permeability (steady and non steady state).
  - contact angles, interfacial curvatures and pore size distributions.
- Diamond Lightsource Synchrotron experiment planned for September 2021.

Hydrogen



Brine imbibition





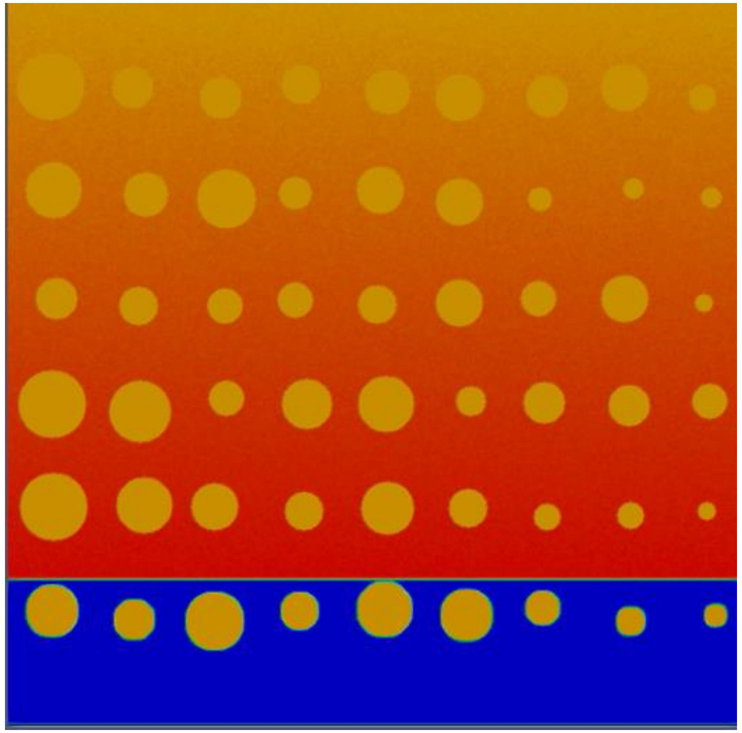
Eike Thaysen (eike.thaysen@ed.ac.uk)

Pore scale modelling

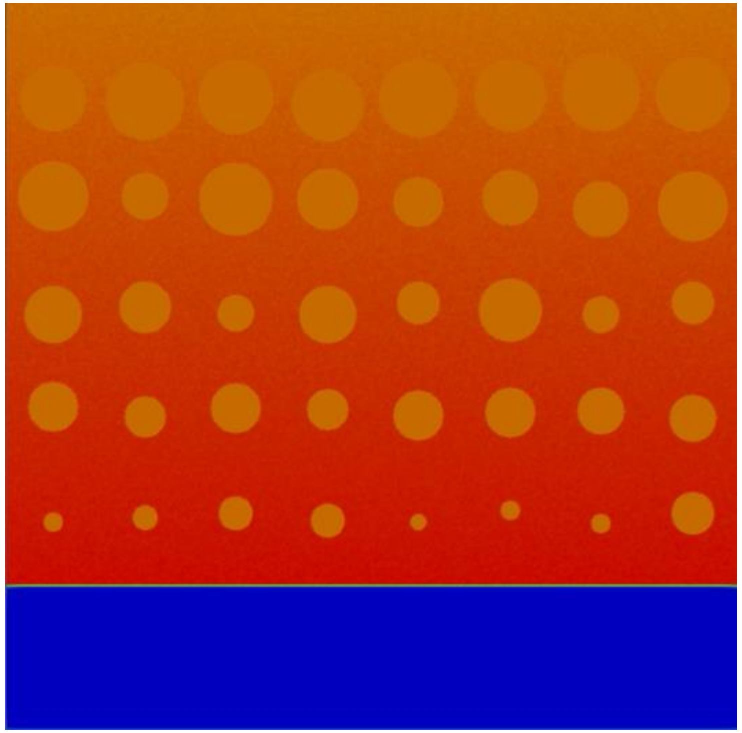
H_2
Water

- Lattice Boltzmann simulations using the Shan-Chen pseudo potential model with a D2Q9 configuration.
- Verified against Poiseuille flow and two-component simulation for capillary rise phenomenon in a capillary tube.
- Confirm that capillarity will have a major influence on the flow behaviour of hydrogen.

Evenly distributed large pore throat diameters



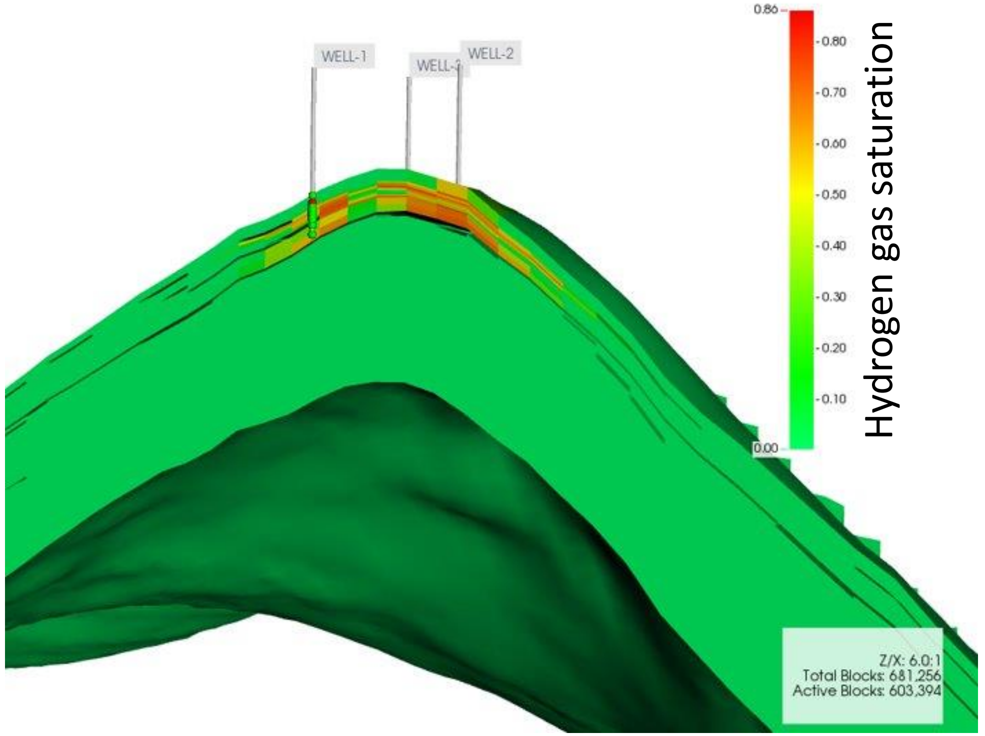
Pore throat diameter reduces towards top



Mehrdad Vasheghani Farahani (mv47@hw.ac.uk) and Ali Hassanpouryouzband (hssnpr@ed.ac.uk)

Reservoir modelling: Saline Aquifer

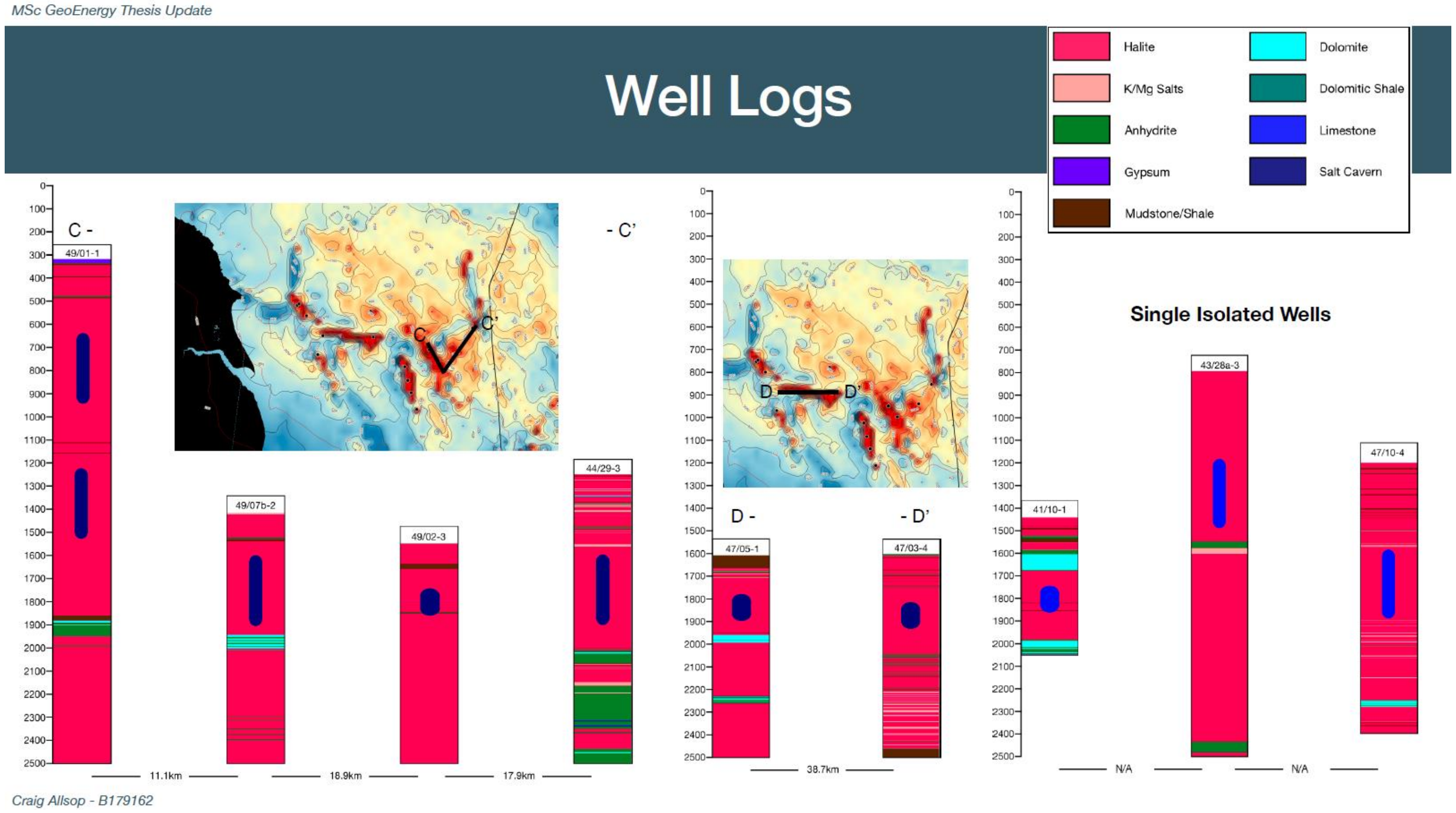
- Pressure dissipation determines the injectivity and productivity of hydrogen in a saline aquifer.
- Low density of hydrogen requires high injection rates
- Cushion gas controls both injectivity and productivity in hydrogen storage.
- The more cushion gas there is, the more hydrogen can be injected and produced, as long as the pressure has enough time to dissipate after the cushion gas injection.



Niklas Heinemann (N.Heinemann@ed.ac.uk)

Salt Cavern Storage

- Zechstein Internal variability.
- Salt integrity to hydrogen.
- Cavern capacity estimates.
- Aldborough gas storage to be repurposed for hydrogen



No showstoppers… so far…

- ✓ Biological site screening: We suggest that storage reservoirs over 122 C^o or with salinities above 4.4 M NaCl equivalent will be less favourable to microbial growth.
- ✓ No significant geochemical reactions have been observed in our reactive experiments.
- ✓ Column height calculations indicate hydrogen will have a higher column height than methane and that this increases with increasing depth.
- ✓ Developed a online tool to provide high accuracy thermodynamic property estimations of hydrogen mixtures (CO_2, N_2, CH_4, natural gas) over a range of temperatures and pressures. **https://www.nature.com/articles/s41597-020-0568-6**
- ✓ Pore scale modelling confirms the importance of capillarity.
- ✓ Cushion gas will play an important role in controlling both injectivity and productivity during hydrogen storage
- ✓ Significant storage capacity in depleted gas fields, minimising subsurface competition with other low carbon geoenergy applications. https://doi.org/10.1016/j.apenergy.2020.116348 and https://doi.org/10.1021/acsenergylett.1c00845

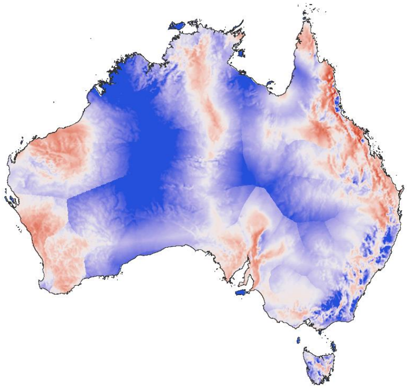
Australian Government
Geoscience Australia

Exploring for the Future Expansion

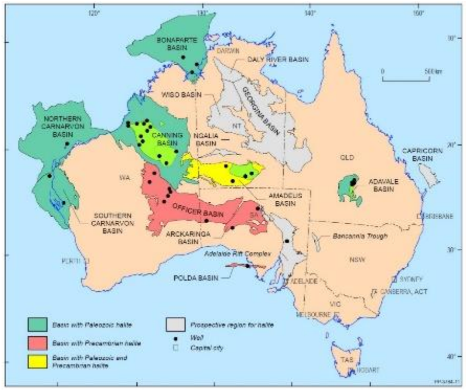
Hydrogen Module (2021 -2024)

Andrew Feitz on behalf of the hydrogen team

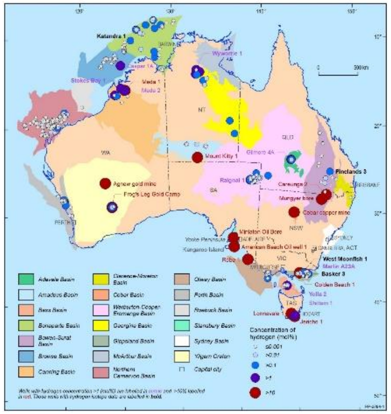
HEFT



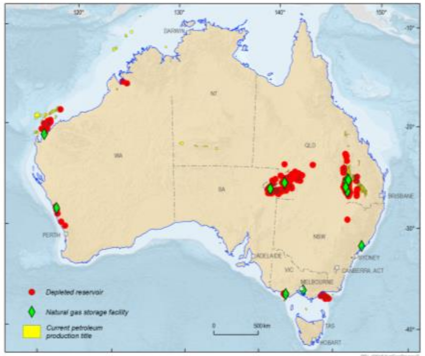
Looking for salt



Hydrogen Studies

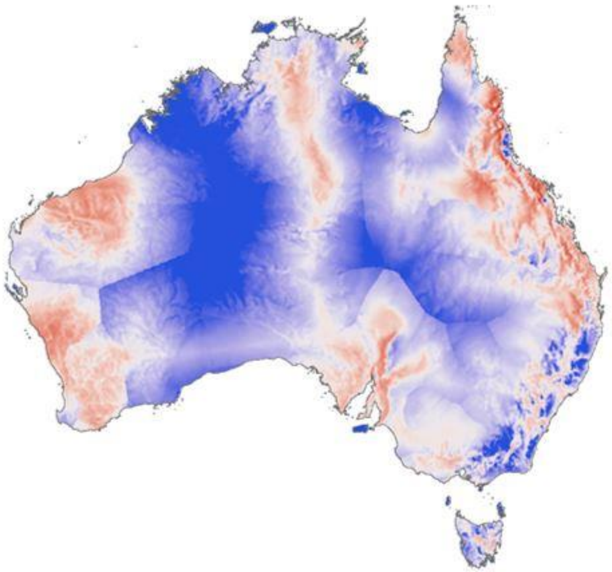


Natural hydrogen

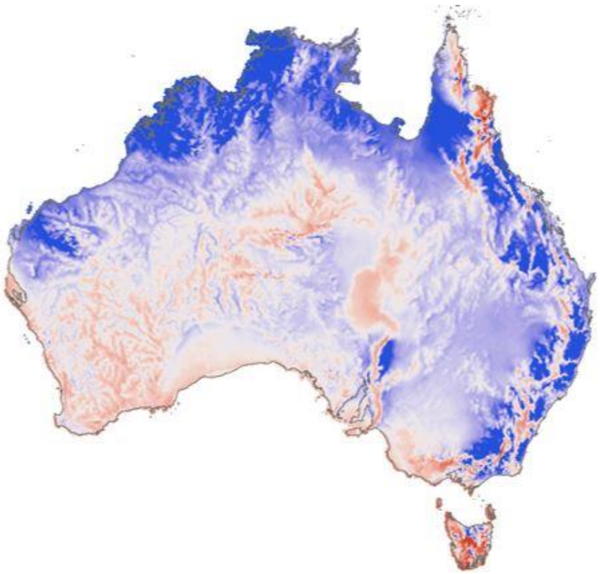


Non salt storage

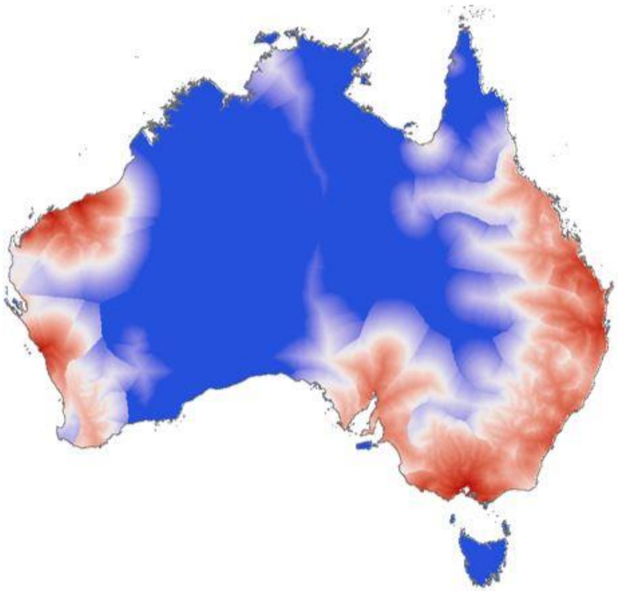
Hydrogen Economic Fairways Tool (HEFT) - Australia very prospective for renewable and CCS hydrogen



Solar



Wind



Gas + CCS

Storage is the missing bit

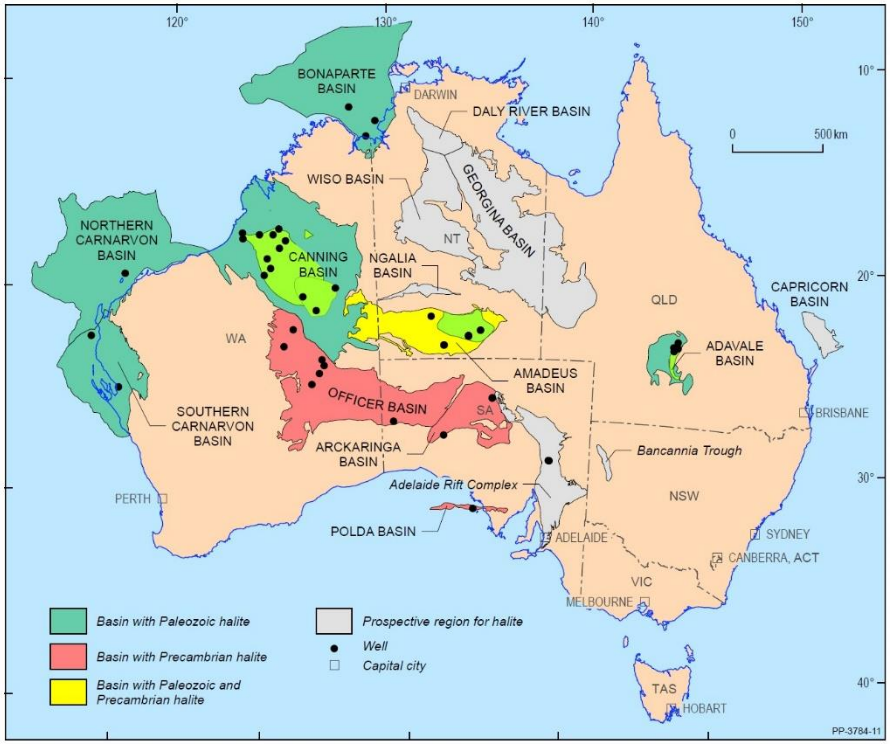
Hydrogen Economic Fairways Tool

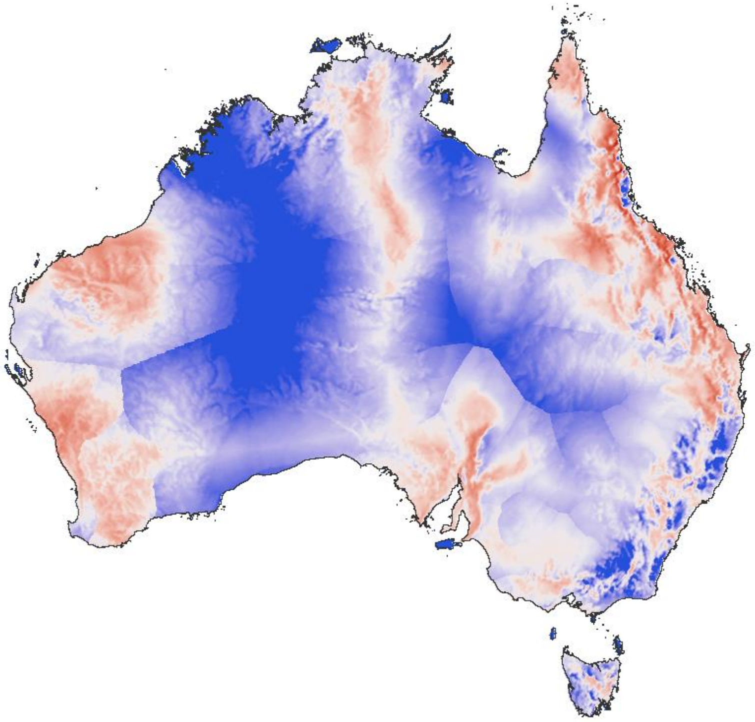
Version 1 – release on 24 March 2021

Version 2 – updates (release in early 2022)

- incorporation of pumped hydro + wind/solar
- include battery storage
- hydrogen storage options (proximity to depleted gas /salt)
- grid connection
- different end product (e.g. ammonia, liquid H2)
- improved CO2 storage data
- hot sedimentary aquifer geothermal?

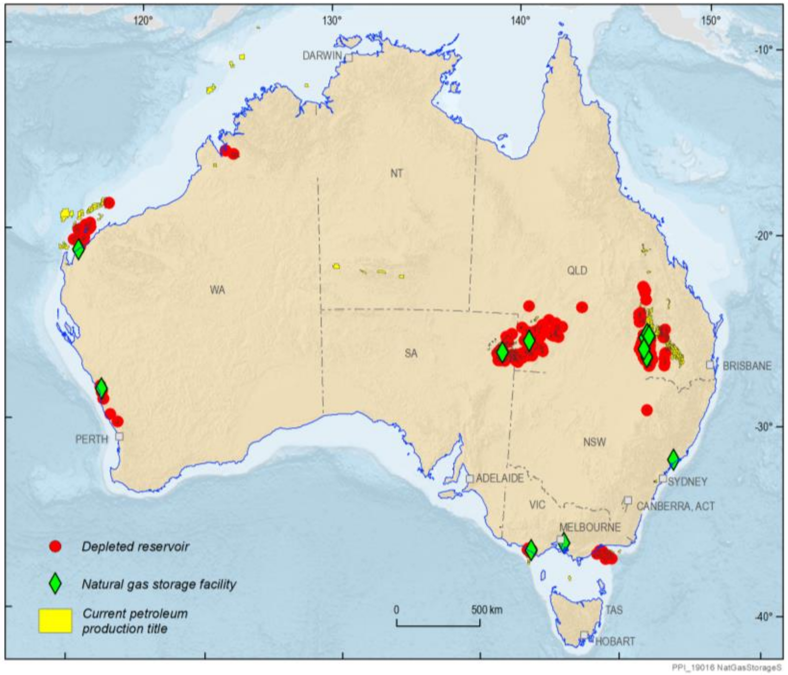
Location of thick salt vs hybrid wind/solar

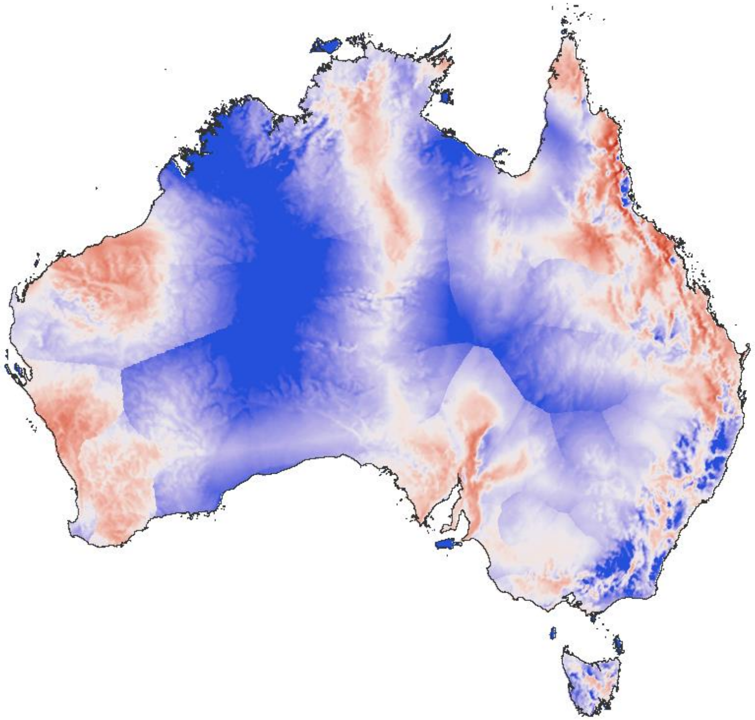




Bright green shows extent of thick onshore halite

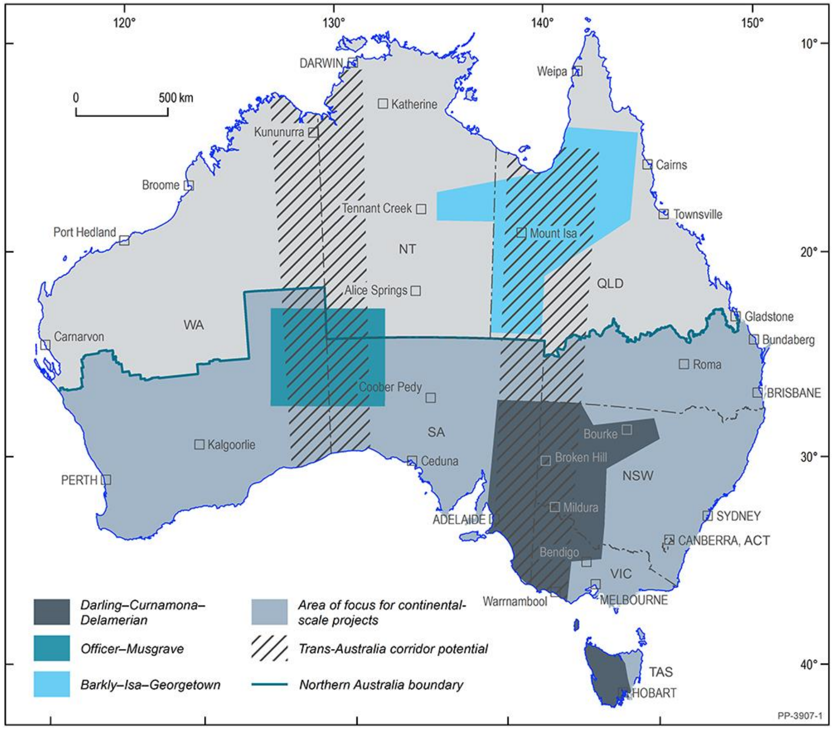
Location of depleted gas fields vs hybrid wind/solar





Exploring for salt prospectivity through EFTF

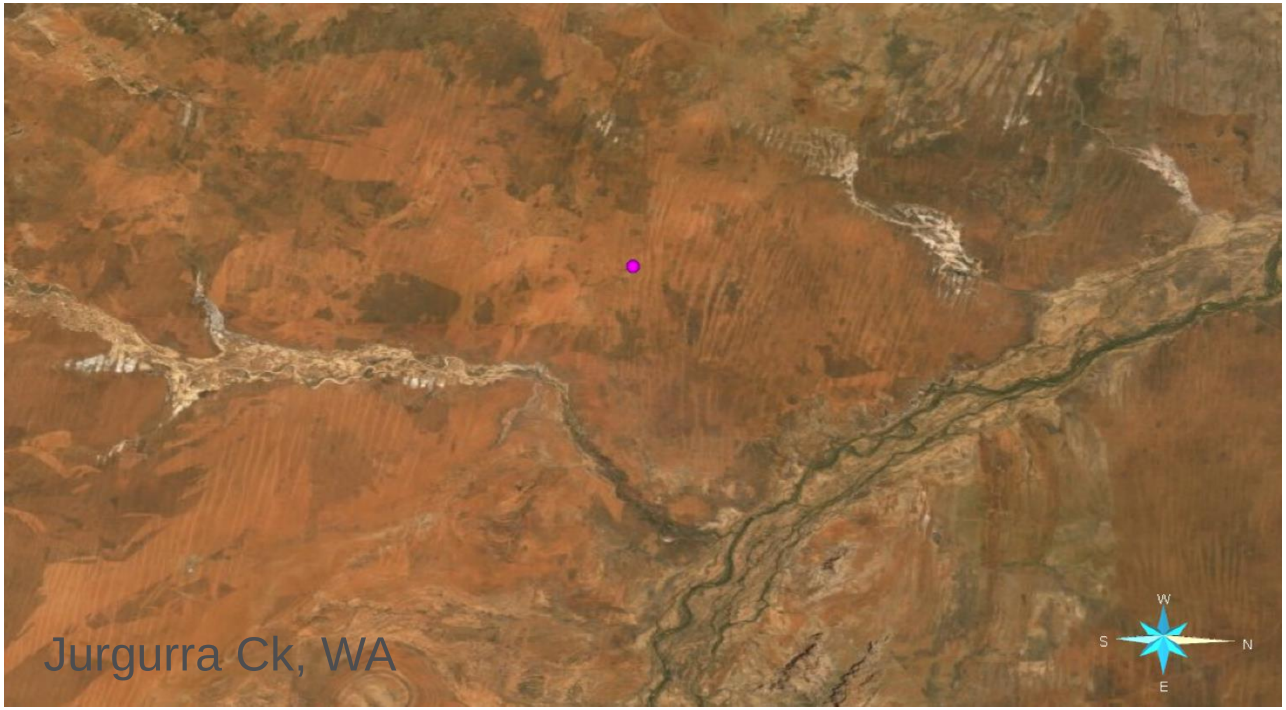
- $125 million expansion of the [Exploring for the Future program]
- Looking for new discoveries of groundwater, conventional and unconventional oil and gas, minerals
- **Also exploring for salt**



Exploring for salt through EFTF – remote sensing

Looking for salt using remote sensing data & machine learning, e.g.

- gravity
- gamma-ray
- surface geology
- terrain derivatives
- magnetics
- satellite imagery



Exploring for salt through EFTF – remote sensing

Looking for salt using remote sensing data & machine learning, e.g.

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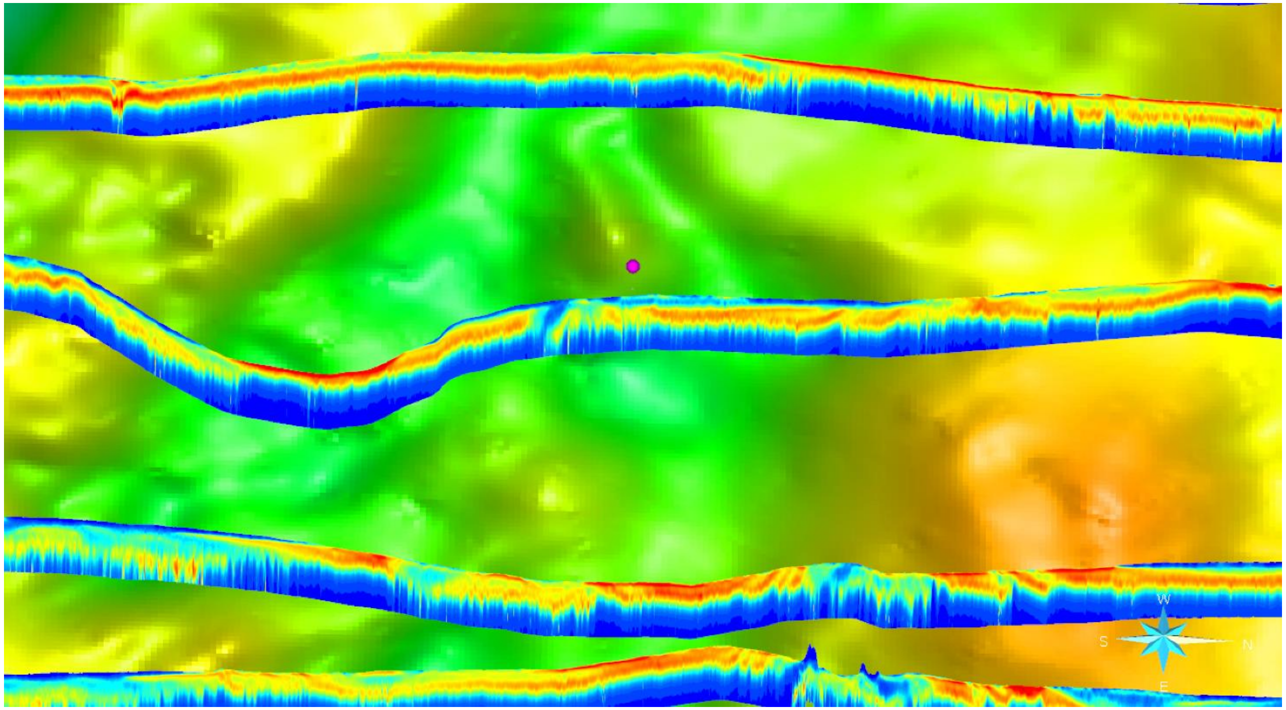
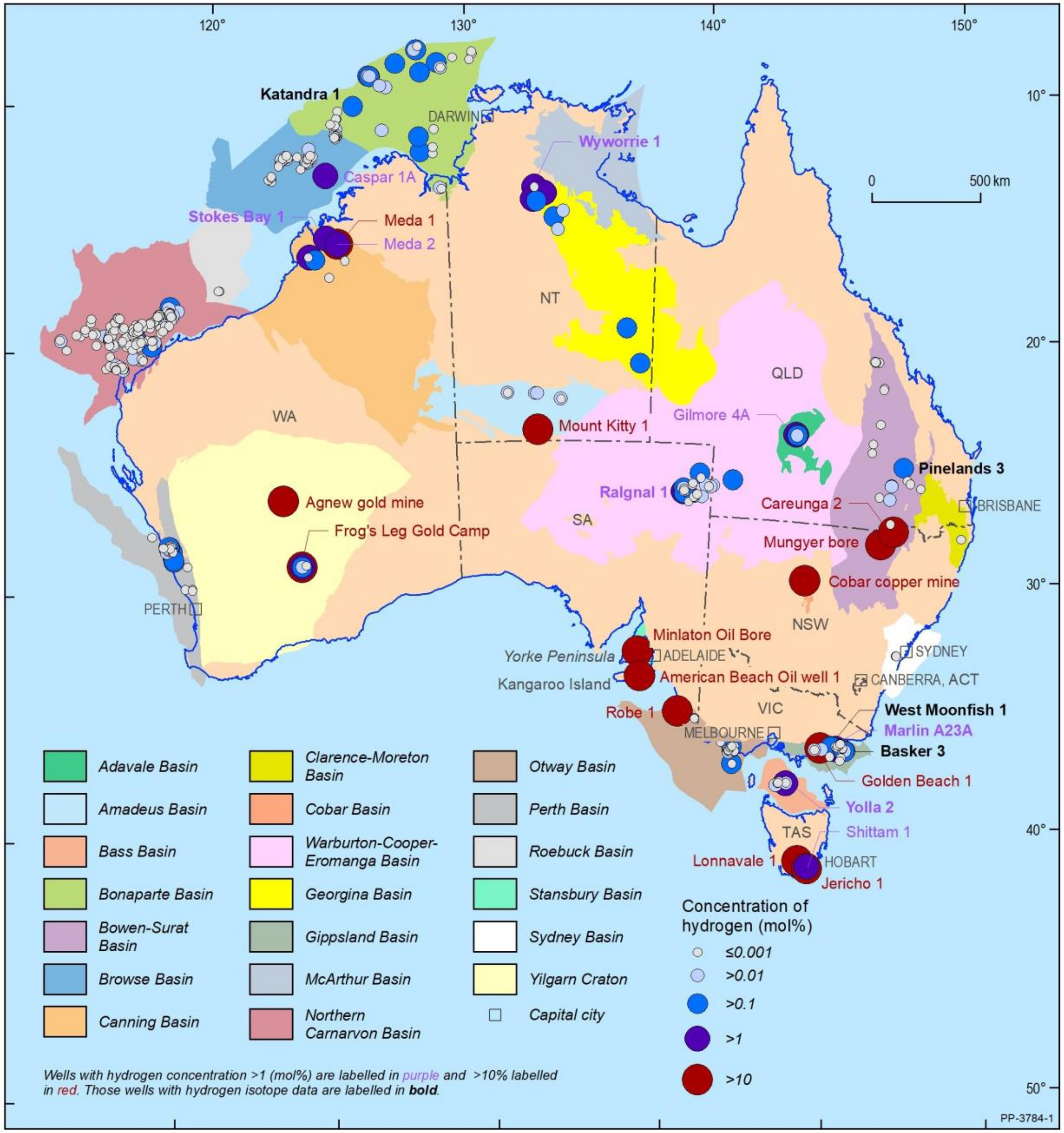


Natural (geologic) hydrogen



Boreham et al (2021) APPEA

Underground Energy Storage

Needed or lifeline of an Industry??

AUSTRIA AG

Agenda

- Advertisement
- Why Energy Storage?
- Hydrogen Storage
- Geo-Methanation

UNDERGROUND SUN.STORAGE

UNDERGROUND SUN.CONVERSION

RAG AUSTRIA AG

RAG Austria AG

Company Profile and Vision

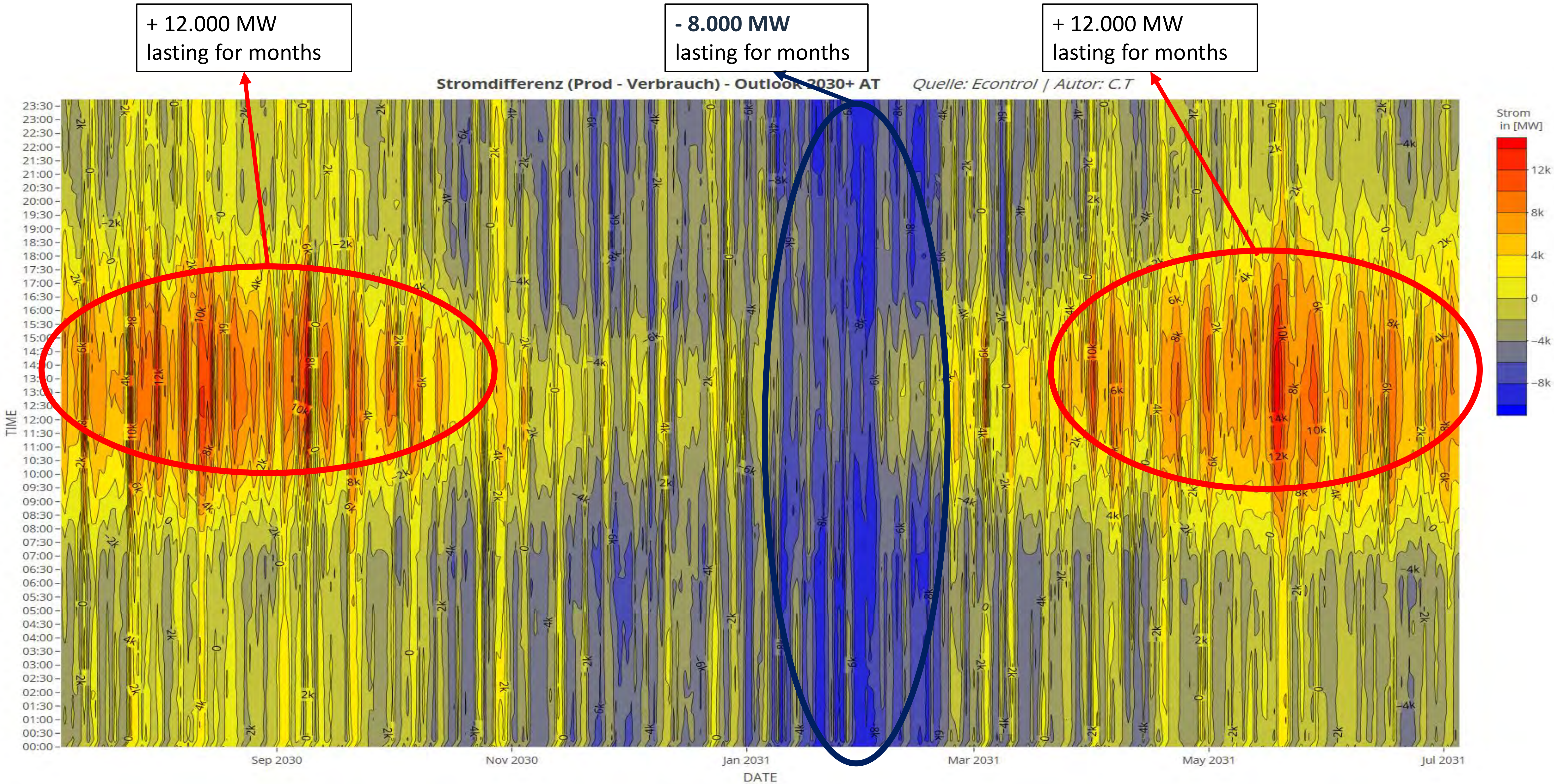
- Sustainable Energy Supplier
- Among leading technical Underground Gas Storage Operators
- State of the art facilities
- Storage volume 66 TWh (~6 bcm)
- Unload capacity 30 GW

- Follow the vision to serve the renewables with our existing assets by constant improvement and innovation

Agenda

- Advertisement
- Why Subsurface Energy Storage?
- Hydrogen Storage
- <u>Geo-Methanation</u>

2030+ residual scenario for electricity in AT

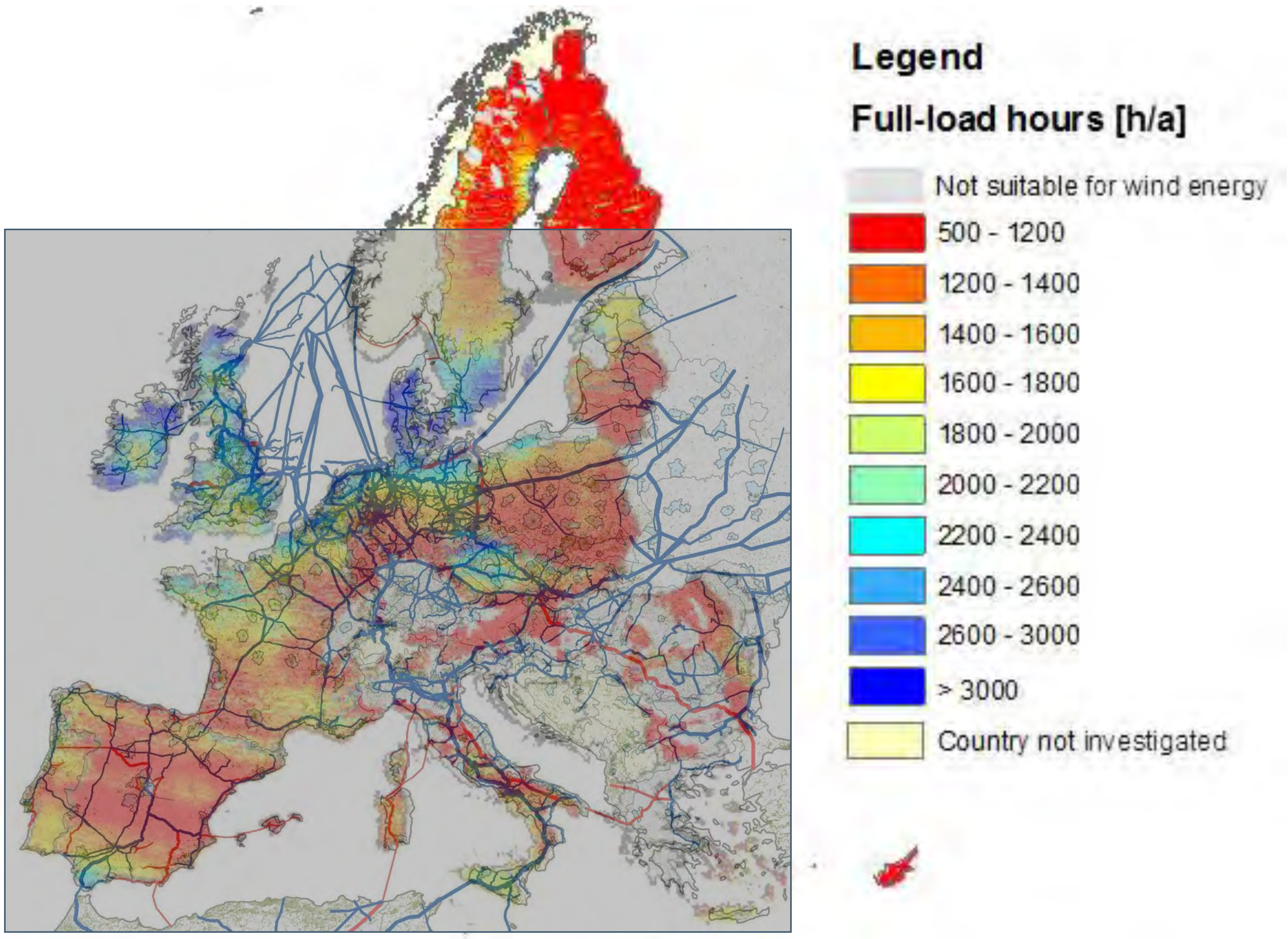


INPUT data: 2030+ vs. 2017 @15 minute intervals:

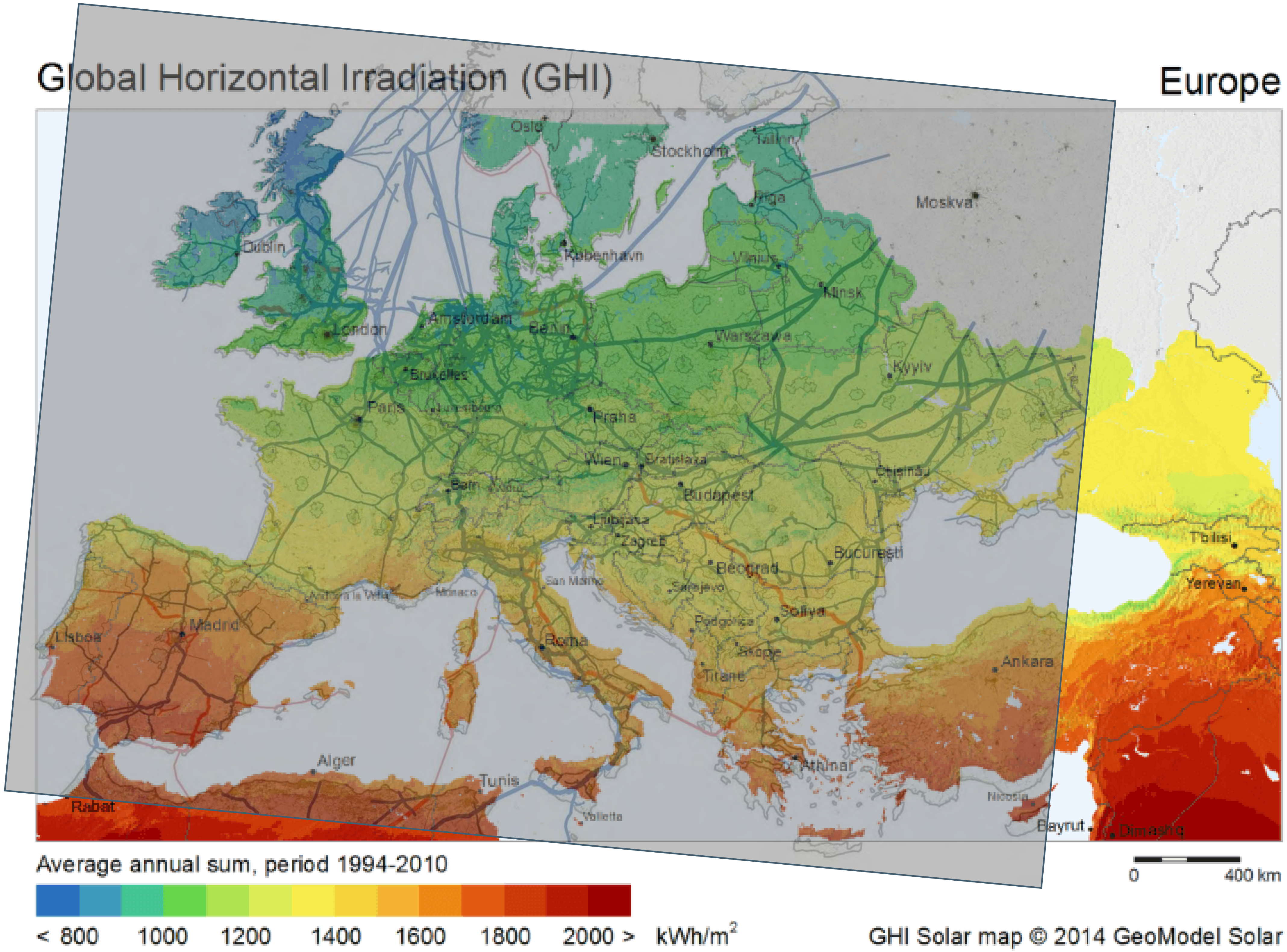
- Demand: +30% (~63 to 81 TWh/a)
- RES generation : Wind x3, Solar x20, Hydro x1 (~ 41 auf 80 TWh/a)

=> Big scale seasonal storage needed

European Potential for Wind Energy Generation



European Potential for Solar Energy Generation



Agenda

- Advertisement
- Why Energy Storage?
- Hydrogen Storage
- Geo-Methanation

UNDERGROUND SUN.STORAGE

UNDERGROUND SUN.CONVERSION

Development of the Underground Sun Storage Project

Motivation

- Gas Storage is Energy Storage
- Gas Storage is ‘invisible‘ and ‘available on demand‘-Energy
- Gas has an existing infrastructure in many regions of the world
- Gas can be greened from 0-100% without changing the system

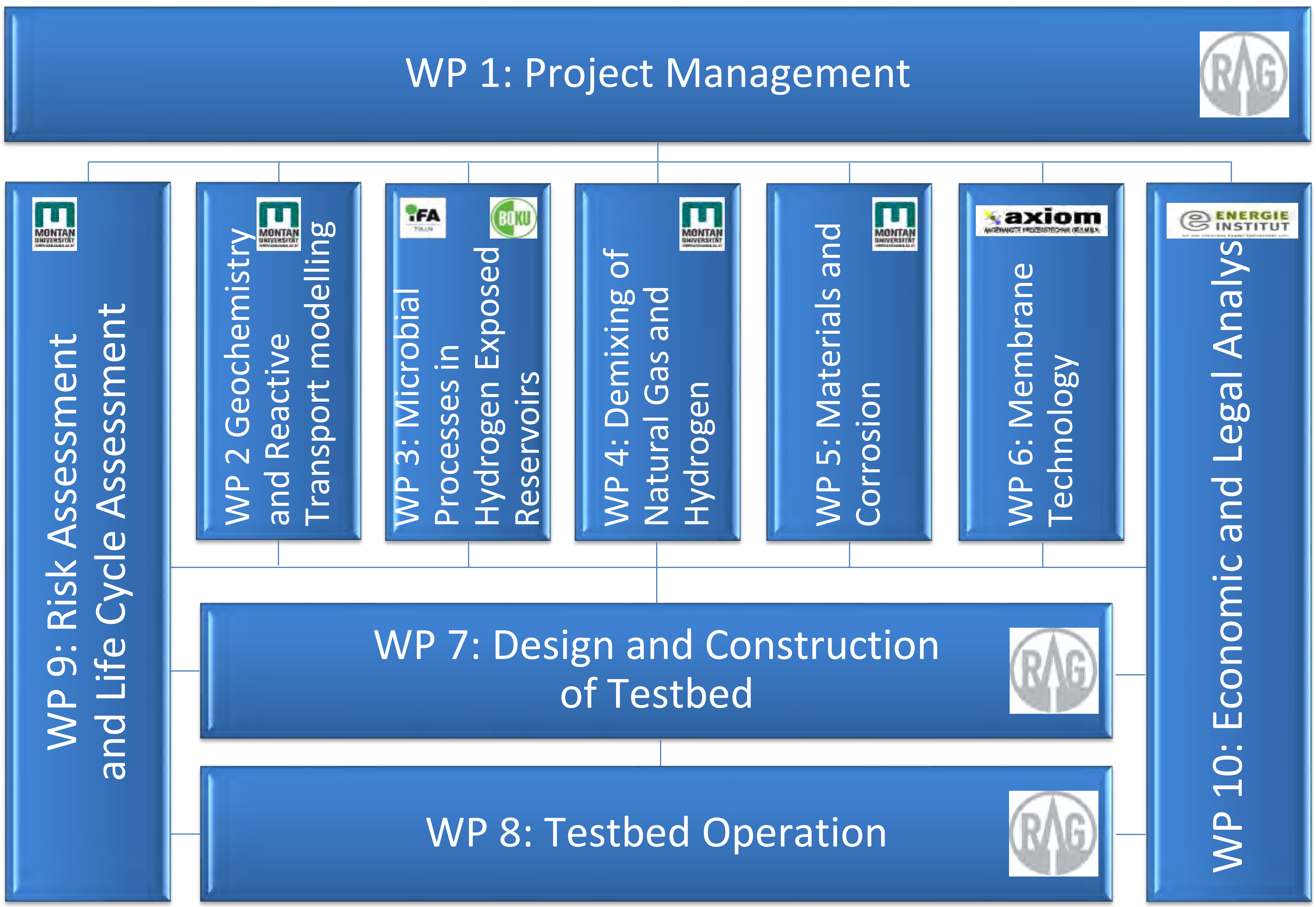
Goals of the Project

- Demonstration of Storability of renewable gases in Gas Storage facilities
- Research on effects of 10% hydrogen admixtures in existing Gas Storage Facilities

Partners

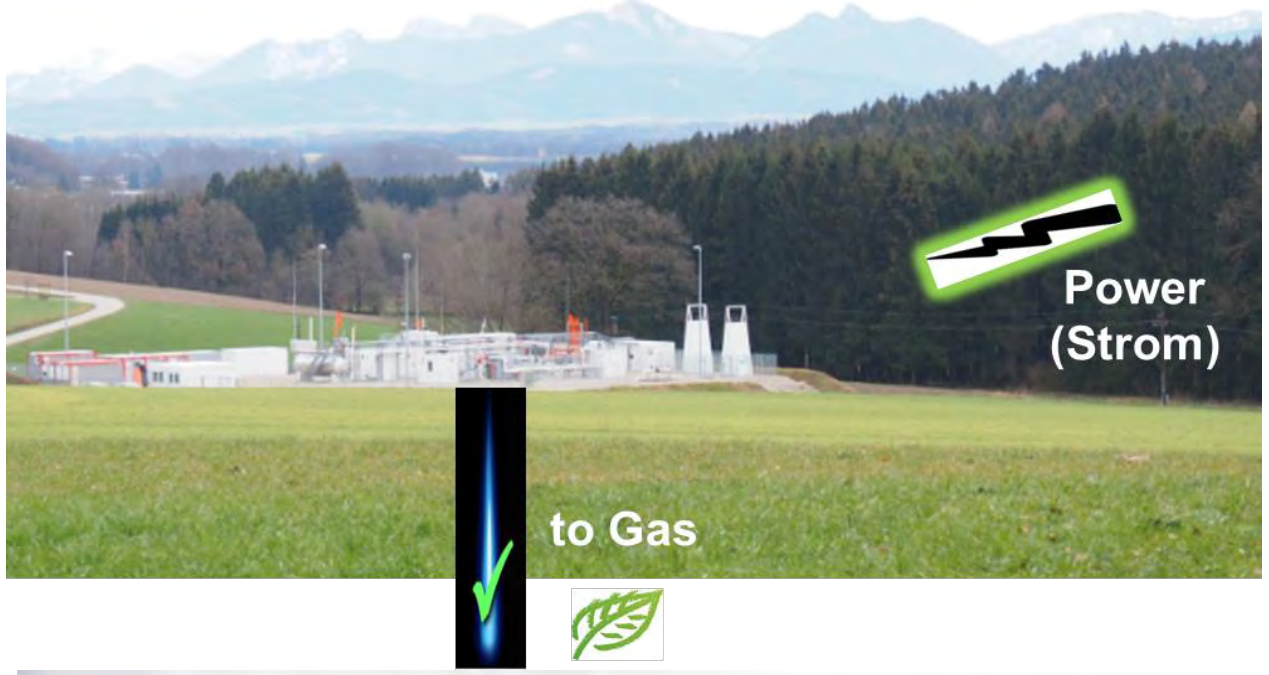
powered by klima+ energie fonds

Project


WP 1: Project Management
WP 9: Risk Assessment and Life Cycle Assessment
WP 2 Geochemistry and Reactive Transport modelling
WP 3: Microbial Processes in Hydrogen Exposed Reservoirs
WP 4: Demixing of Natural Gas and Hydrogen
WP 5: Materials and Corrosion
WP 6: Membrane Technology
WP 10: Economic and Legal Analys
WP 7: Design and Construction of Testbed
WP 8: Testbed Operation

Underground Sun Storage

UNDERGROUND SUN.STORAGE



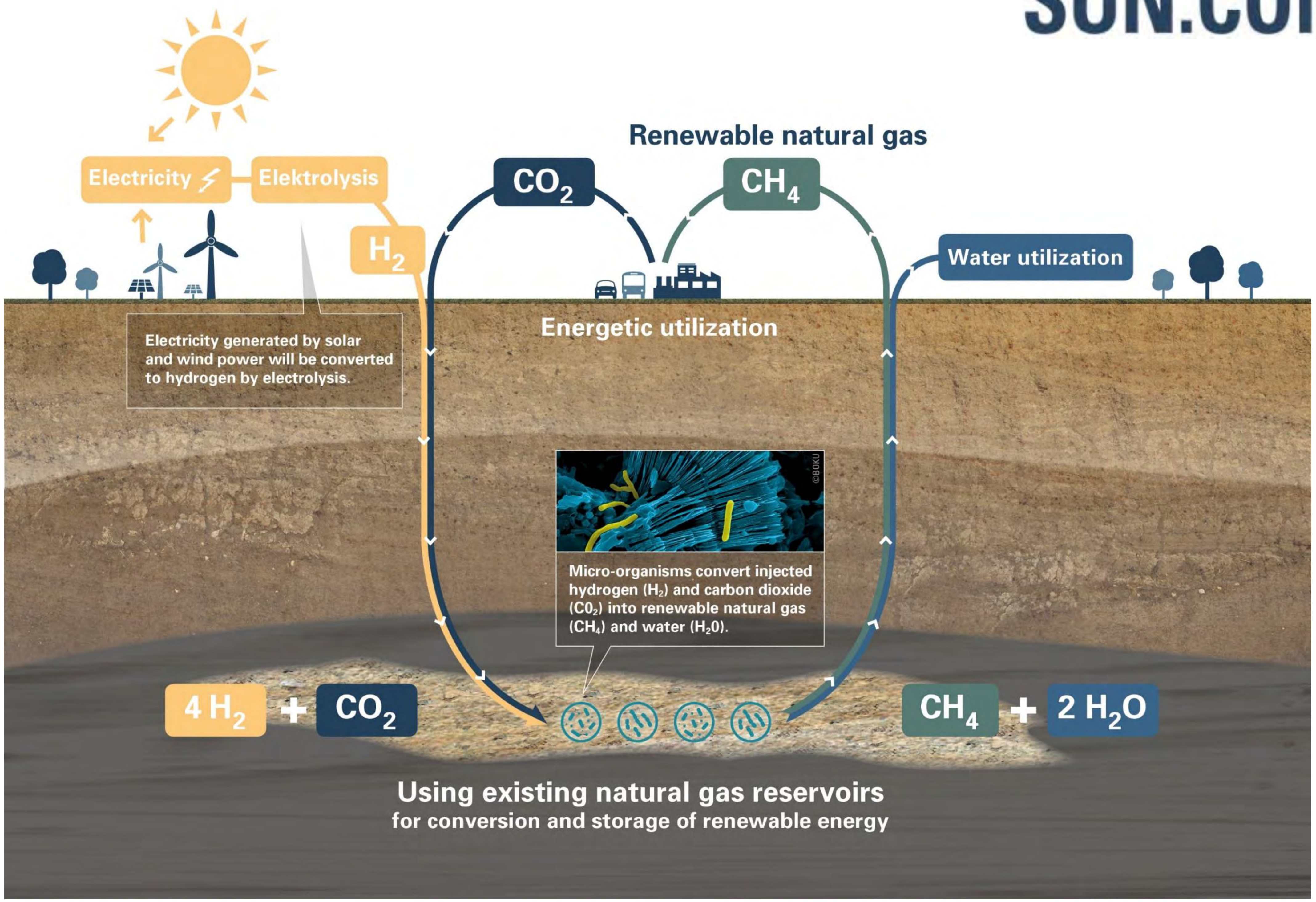
- Renewable Energy can be stored as Hydrogen in underground gas reservoirs.
- 10 % share of H_2 tested (partial pressure up to 75 bar(a))
- Project confirmed scale up potential to RAGs commercial facilities
- Open: Assignability to other geological reservoir settings
- Key Parameters Identified
- 100 % Hydrogen in natural gas reservoirs is the next development objective and will be done in the project USS2030 (already started)
- https://www.underground-sun-storage.at/

Agenda

- Advertisement
- Why Energy Storage?
- Hydrogen Storage — UNDERGROUND SUN.STORAGE
- Geo-Methanation — UNDERGROUND SUN.CONVERSION

Convert a one way industry into a sustainable cycle industry

UNDERGROUND SUN.CONVERSION



But why??

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WP 1: Project Management

WP 2: Microbial Methanogenesis in porous Reservoirs

WP 3: Numerical Simulation of Microbial Processes

WP 4: Materials and Corrosion (Steel, Seals, Cementation)

WP 5: Product Gas Conditioning

WP 8: Ability for Upscaling

WP 9: Potential Analysis

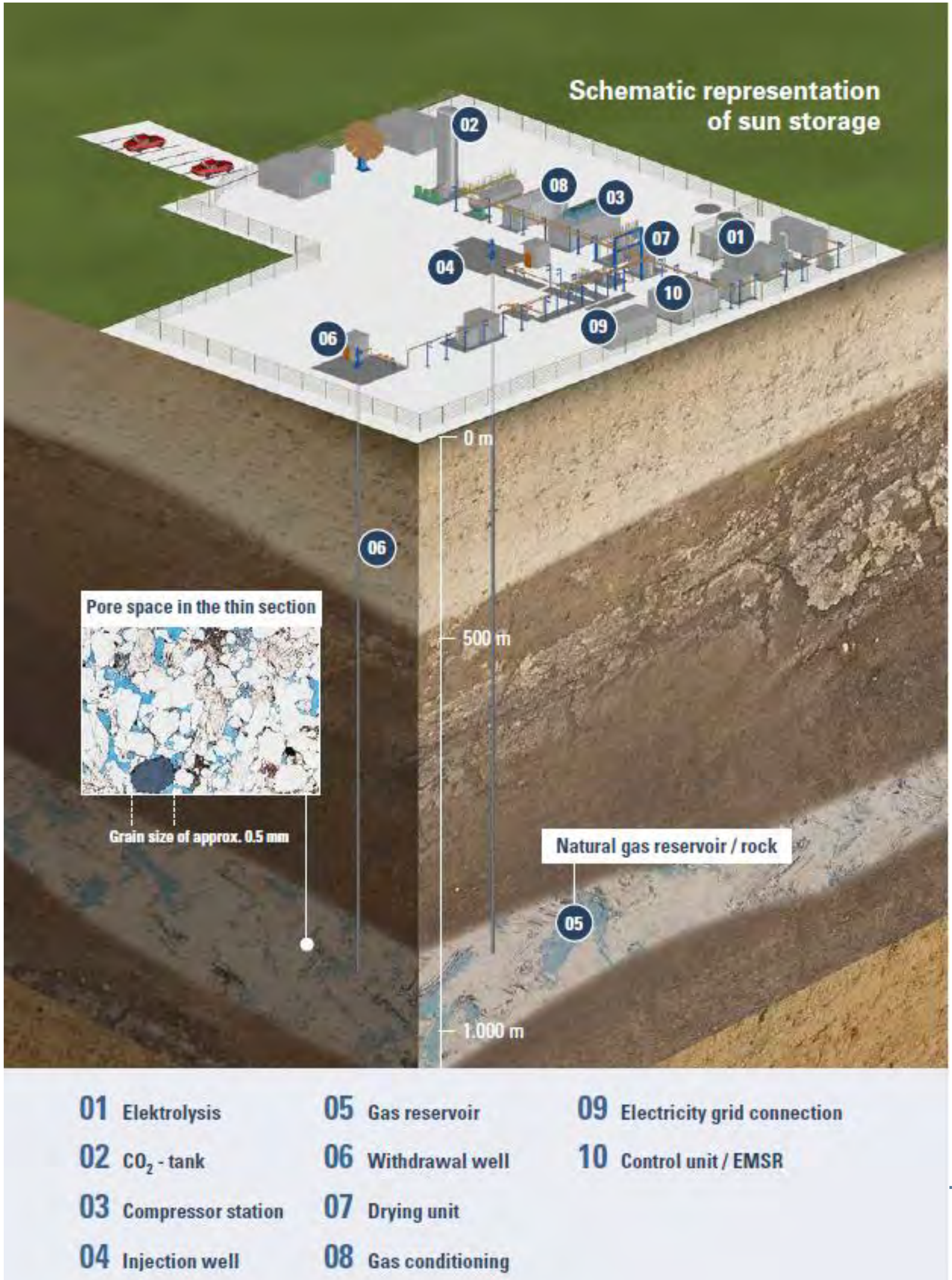
WP 6: Design, Construction and Operation

In-Situ Reservoir Batch Experiment

WP 7: Design, Construction and Operation

In-Situ Reservoir Cycle Experiment

Watersampling



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In-situ Field Experiments

- Construction and Commissioning finished
- 5 “major” Batches (WGV ~580. kNm³)
  - 10 vol.% H_2; 2,5 vol.% CO_2
- 9 “minor” cycles (WGV ~40. kNm³)
  - 20 vol.% H_2; 5 vol.% CO_2
- Measurement
  - Surface Flow meters and GC
  - THP, BHP, BHT
  - Water Samples

Second Well for Cycle Experiments

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Conclusion

- Conversion in the reservoir is possible
- Different operation scenarios are under investigation
- Gas mixing needs to be addressed to forecast the composition of the product gas
- Safe storage of CO_2 and H_2 in a subsurface reservoir is possible
- One Follow up project already approved and running (USC FlexStore)
- Second Follow up Project C-CED starting in fall

Contact

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Project Partners:

MONTAN UNIVERSITÄT, acib austrian centre of industrial biotechnology, ENERGIE INSTITUT an der Johannes Kepler Universität Linz, BOKU, IFA TULLN, axiom, klima+ energie fonds

You can't spell storage without RAG!

RAG AUSTRIA AG

Report 221

Hydrogen Storage Potential of Depleted Oil and Gas Fields in Western Australia
Literature Review and Scoping Study

RISC

The Government of Western Australia has developed a renewable hydrogen strategy with the vision that Western Australia will become a significant producer, exporter and user of renewable hydrogen. Western Australia has outstanding potential for renewable energy, with an abundance of sun, wind and space. The Western Australian Renewable Hydrogen Roadmap (November 2020) includes the evaluation of utilizing depleted oil and gas fields for hydrogen storage. A key aspect is the ability to store the hydrogen on a transitory basis and to be able to recover the hydrogen in high concentrations.

The Hydrogen Storage Potential of Depleted Oil and Gas Fields in Western Australia Literature Review and Scoping Study was funded through the Western Australian Government's COVID-19 Response 'Renewable Hydrogen Initiatives', which is administered by the Department of Jobs, Tourism, Science and Innovation. This Report was prepared by RISC and includes a high-level review of other examples of underground hydrogen storage such as aquifers, salt caverns, underground mine sites and tunnels.

RISC has screened 23 onshore depleted gas and oil fields in Western Australia for suitability to meet the storage need of renewable hydrogen. The company has identified seven fields as good candidates for hydrogen storage projects along the west coast of Western Australia. RISC's mapping of renewable hubs relative to the subsurface sites shows that there is ample depleted oil/gas field storage capacity in the Perth Basin.

Further details of geoscience products are available from:

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Department of Mines, Industry Regulation and Safety
100 Plain Street
EAST PERTH WA 6004
Phone: (08) 9222 3459   Email: publications@dmirs.wa.gov.au
www.dmirs.wa.gov.au/GSWApublications