Natural Hydrogen Play-Type Models from a Development Perspective

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This paper is a non-peer reviewed preprint submitted to EarthArXiv

It has been submitted for peer-reviewed Full Journal Paper publication to **International Journal of Hydrogen Energy**, January 2025

Abstract

This paper proposes a broad classification of natural hydrogen occurrences from a viewpoint of not only exploration geology but also development-potential and ability to meet industrial needs. Conceptually, working subsurface "hydrogen systems" comprise the same key elements as their "petroleum system" counterparts namely: Source, Reservoir, Trap and Seal. Considering success or failure on these "system elements" and consequences for technical development-potential, this paper categorizes "finds" and prospects into three "hydrogen play types": 1) "focussed seepage" plays where there is a hydrogen source but minimal trapping and where hydrogen concentrations reflect localized migration pathways, mostly of dissolved hydrogen; 2) "coal-bed hydrogen" plays where hydrogen is adsorbed on a molecular scale in coals; 3) "reservoir-trap-seal" plays with gaseous hydrogen columns trapped underneath an impermeable seal.

It appears that only "reservoir-trap-seal" hydrogen plays could potentially meet the supply needs of industrial facilities. To date, no accumulations of this type have unambiguously been discovered.

Highlights

- Natural hydrogen occurrences are grouped into three play-types considering development potential and ability to meet commercial demand.
- "Focussed H_2 seepages" which may be relatively common, will be challenging to commercialize due to low Resource Density, low well productivity and high associated water production.
- "Coalbed H_2" finds also suffer from low well productivity and from the same environmental concerns that hamper CBM development (e.g. high co-production of water, very large surface footprint).
- Accumulations of H_2 gas in "Reservoir-Trap-Seal" configurations could potentially meet the supply needs of industrial facilities. However, no conclusive finds of this type have been made to date.

Keywords

Natural Hydrogen, White Hydrogen, Play Classification, Resource Assessment, Field Development, Decarbonization

1. Introduction

To meet net-zero goals, hydrogen is projected to account for a significant amount of the future energy supply in some sectors, with the global demand increasing more than fivefold by 2050 [1]. Future supply of hydrogen is expected to be a combination of hydrogen generated via electrolysis of water using renewable electricity (also known as green hydrogen) and from fossil fuel sources coupled with carbon capture, utilization, and storage (also known as blue hydrogen). A third, more speculative supply of hydrogen to future energy systems could come in the form of "natural" or "geological" hydrogen sourced from the subsurface (also known as white hydrogen). Encounters of "geological" hydrogen at several locations (e.g., Mali [2] [3], Eastern France [4], Albania [5], South Australia [6] [7], and the US Mid-West Ridge [8]) and the description of "fairy circles" (oval-shaped structures with anomalous vegetation, attributed to escaping gases including hydrogen [9], challenge the common belief that hydrogen as a pure, molecular substance, is rare in the shallow subsurface. Most subsurface hydrogen occurrences to-date have however been encountered by serendipity while exploring for water or hydrocarbons [10], stressing the need for dedicated exploration methodologies.

Reviews to date of natural hydrogen systems have mostly focussed on exploratory aspects such as hydrogen occurrences by geologic setting [11] [12], hydrogen-sources and generation processes [9] [13] [14], hydrogen flux-rates and global hydrogen-system potential [15], and hydrogen detection [6] [16]. However, for natural hydrogen to materially contribute to industry and energy-systems decarbonization, research should also consider the development potential of prospects and finds. The latter is important as it helps identification of those natural-hydrogen plays and prospects that, in case of exploration success, have the highest chance of being commercially viable and able to meet the offtake requirements of industrial buyers. At present, hydrogen demand is mostly from large industrial facilities like petroleum refineries (typical demand in the order of 50,000 ton hydrogen per annum per average plant) and ammonia plants (around 280,000 ton hydrogen per annum per average plant) [17] [18]. As shown in Figure 1, decarbonization could create H_2 demand for other large applications such as “green” steelplants but also smaller, local hydrogen-offtake opportunities like vehicle fuelling hubs etc. However, even the smallest anticipated commercial applications would likely require supply in excess of 1,000 ton H_2 per year and a supply commitment for several years (a good portion of the facility’s lifespan).

In the above context, this paper proposes a broad classification of natural hydrogen occurrences into play-types from a viewpoint of not only exploration geology but also development potential and ability to meet commercial demand. Hydrogen phase (gaseous vs aqueous) and nature of storage (trapped in porous layers at excess pressure, adsorbed at molecular scale or merely migrating through porous and permeable rock) are key considerations in distinguishing the different Play-Types. Each Play-Type will be illustrated by actual field examples for which estimates of Hydrogen Resource-per-unit-area, well productivity, water production and other byproducts, and indicative development-project metrics will be presented, to illustrate the relative attractiveness of different play-types from an exploitation perspective.

2. Material

This paper uses a combination of 1) a review of open-domain research papers on natural hydrogen, and 2) site-specific data on the case studies used to illustrate the different play-types (Bourakebougou in Mali; Folschviller in Lorraine, France; and Monzon in Aragon, Spain) to derive its conclusions. References to relevant research papers and to the site-specific data are provided within the respective sections of this paper.

3. Theory and Calculation Methods

To illustrate the technical development potential (i.e., attractiveness from an exploitation perspective) of different natural hydrogen settings or “play types”, this paper presents four main sets of indicative metrics, for selected case-studies of each play type by estimating:

1. Hydrogen Resource-per-unit-area (“Resource Density”);
2. Well productivity;
3. Water production and other byproducts;
4. Development-project metrics (such as well count and resource-area required for a certain amount of production).

Sections below explain the methodologies deployed in calculating each of these metrics. Calculations were done in Microsoft EXCEL™ making use of a plug-in library of petroleum-engineering equations (Petroleum Office™).

3.1. Hydrogen Resource-Density

The use of Resource-per-unit-area (also called "Resource Density" or "Richness") as used in this paper, is not uncommon in settings like resource plays where the lateral extent of the resource area (or trap) remains uncertain or lacks delineation.

As described in a number of reviews (e.g. [11], [19]) hydrogen can locally be found in the earth subsurface in four main forms namely: 1) as a dissolved gas (aqueous), 2) as a gas adsorbed at molecular scale (onto adsorbents like coal), 3) as a residual gas (immobile inclusions), and 4) as a free gas. Estimates of Hydrogen Resource-per-unit-area are therefore made with different formulas, depending on which of these four "hydrogen forms" is dominant in a given subsurface setting. Due to the high volatility and reactivity of hydrogen, finding material quantities of it as a free molecule in either one of the above forms may be rare. This paper does not intent to discuss these probabilities, i.e., the Chance of Discovery. Instead, the purpose here is to present methods for quantifying the amount of hydrogen resource, assuming an accumulation of hydrogen is found in the subsurface. Furthermore, the formulas presented below allow the reader to calculate production outputs for other sets of input-parameter combinations.

3.1.1. Aqueous Hydrogen Resource-Density

In settings where hydrogen is dominantly in aqueous form (dissolved in formation water) alongside smaller amounts of residual H_2 gas, steps to calculate the Hydrogen Resource-per-unit-area are as follows.

First, reservoir PoreVolume-per-unit-area (PV) is computed as:

$$PV = h * NtG * Por$$

where h = gross reservoir thickness, NtG = reservoir net-over-gross ratio and Por = net-reservoir porosity.

Then, maximum hydrogen-solubility at reservoir conditions is calculated using Henry's law:

$$C_i = P_i / K_H$$

where C_i = initial H_2 solubility, P_i = initial reservoir pressure and K_H = Henry's constant for hydrogen at reservoir temperature. For the sake of simplicity, indicative resource-values estimated in this paper use a single value for Henry's Constant for Hydrogen (1282.05 l*atm/mol) irrespective of reservoir temperature.

Residual H_2-gas-in-place-per-unit-area ($H_2g_{res}IP$), at initial conditions in mass units, is then calculated as:

$$H_2g_{res}IP = PV * S_g * H_2frac / B_{gi} * H_2den$$

where S_g = total (residual) gas saturation including H_2 plus other gases, H_2frac = fraction of hydrogen in the gas (for the sake of simplicity, it is assumed that residual and dissolved gas have the same H_2 content), B_{gi} = gas-expansion factor for hydrogen at initial reservoir conditions (estimated from industry-standard equations, i.e., using pseudo-critical temperature and pressure for hydrogen to calculate a hydrogen gas-compressibility “Z” factor [20], and H_2den = density of hydrogen at standard conditions.

Dissolved Hydrogen-In-Place-per-unit-area (H_2aqIP), also in mass units, is then estimated as:

$$H_2aqIP = PV * (1-S_g) * H_2frac * C_i * H_2moleden$$

where $H_2moleden$ = molecular density of hydrogen. In above equation, H_2frac is multiplied with the maximum H_2 solubility at initial conditions (C_i) to reflect the partial pressure of H_2 at the gas-water interface.

Finally, Total Hydrogen In-Place-per-unit-area (H_2IP) is estimated by summing the aqueous and residual-gas components:

$$H_2IP = H_2aqIP + H_2g_{res}IP$$

The principal recovery mechanism in aqueous-hydrogen systems would be pressure depletion, achieved by lifting formation water from the wells. Pressure depletion lowers hydrogen solubility, releasing dissolved hydrogen from the formation water (from water produced by the well but also within the pressure sink around the well). Depletion will also cause expansion of residual gas bubbles which, in turn, increases gas saturation and (assuming initial S_g was near or at critical) remobilizes some of this originally residual gas.

Recovery efficiency of aqueous systems remains speculative. The closest analogue to aqueous hydrogen exploitation may be the studies of methane-extraction potential from aquifers (e.g. [21] [22]); however, to date this has not been attempted commercially. Our method of estimating recoverable hydrogen assumes that fluid lifting in producer wells can achieve a certain amount of “average” pressure depletion over the resource area they are drilled into. And that the hydrogen released (from solution and remobilized H_2 gas) as a result of that depletion, would make its way to the producer wells within the production time period. The assumed “average” pressure-depletion achieved over a Resource area at the end of production, should be reflective of the specifics of the aqueous H_2 reservoir (thickness, porosity, permeability, pressure, connectivity), its attached aquifer size and also the assumed producer-well design and completion concept.

With these assumptions, steps to quantify the Recoverable Hydrogen-per-unit-area are as follows.

First, hydrogen solubility at depleted reservoir conditions is calculated as:

$$C_r = P_r / K_H$$

where C_r = depleted H_2 solubility, P_r = depleted reservoir pressure. K_H = Henry’s constant for hydrogen.

Residual H_2-gas-in-place-remaining-per-unit-area ($H_2g_{res}Rem$), at depleted reservoir conditions in mass units, is calculated as:

$$H_2g_{res}Rem = PV * S_g * H_2frac / B_{gr} * H_2den$$

where B_{gr} = gas-expansion factor for hydrogen at depleted reservoir conditions (estimated using industry-standard equations).

Dissolved Hydrogen-In-Place-remaining-per-unit-area (H_2aqRem), at depleted reservoir conditions in mass units, is estimated as:

$$H_2aqRem = PV * (1-S_g) * H_2frac * C_r * H_2moleden$$

Finally, Recoverable Hydrogen-per-unit-area or "Recoverable Hydrogen Resource-Density" (H_2UR) is then quantified as:

$$H_2UR = H_2IP - H_2aqRem - H_2g_{res}Rem$$

It must be stressed that this analytical approach only provides an indicative estimate of recoverable Hydrogen-Resource potential for a given play site; it cannot capture the details of reservoir depletion, impact of reservoir heterogeneity etc.

3.1.2. Adsorbed Hydrogen Resource-Density

In settings where hydrogen gas is adsorbed, on a molecular scale, into the mineral fabric of adsorbent rocks like coals or organic-rich shales, steps to calculate the Hydrogen Resource-per-unit-area are as follows.

First, total adsorbed gas-in-place-per-unit-area (GIP) is calculated as:

$$GIP = h * RHO_b * GC_{raw}$$

where h = net thickness of adsorbent rock, RHO_b = bulk density of adsorbent rock and CG_{raw} = raw gas content in adsorbent rock (per bulk unit of mass). If Gas Content data is not raw but dry and ash-free (GC_{DAF}), the formula to estimate GIP is:

$$GIP = h * RHO_b * (1- Ash – Moisture) * GC_{DAF}$$

where Ash and Moisture content of the adsorbent rock are expressed in weight fractions.

H_2-gas-in-place-per-unit-area (H_2GIP), in mass units, is then calculated as:

$$H_2GIP = GIP * H_2frac * H_2den$$

where H_2frac = fraction of hydrogen in the total adsorbed gas and H_2den = density of hydrogen at standard conditions.

The principal recovery mechanism in adsorbed gas systems is again pressure depletion, achieved by lifting formation brine from producer wells. Pressure depletion lowers gas adsorption-capacity and hence releases gas from the adsorbent rock, either from the onset of fluid lifting (in case actual gas content is at maximum adsorption capacity of the adsorbent rock) or, in case of undersaturated adsorbent rock, once pressure depletion has lowered adsorption capacity of the rock to the point where it equals the actual gas content. Gas desorbs into the fracture and cleat system of the coals and from there, it flows towards and into the wells.

Since coal-bed-methane (CBM) developments are a producing example of adsorbed gas systems, recovery efficiencies observed in CBM may be considered as analogues for the recovery efficiency achievable from adsorbed-hydrogen plays. Obviously, analogue selection should consider similarity in adsorbent-reservoir rock type, thickness, permeability and burial depth (i.e. pressure and temperature).

Recoverable Hydrogen-per-unit-area or “Recoverable Hydrogen Resource-Density” (H_2UR) can hence be estimated as:

$$H_2UR = H_2GIP * RF$$

where RF = (analogue) Recovery Factor

3.1.3. Free Hydrogen-Gas Resource Density

In settings where hydrogen is dominantly in gaseous form, trapped in porous reservoirs under excess pressure retained by impermeable caprock, steps to calculate the free Hydrogen-Gas Resource-per-unit-area are similar to conventional gas, as follows.

First, reservoir PoreVolume-per-unit-area (PV) is computed as:

$$PV = h * NtG * Por$$

where h = gross reservoir thickness, NtG = reservoir net-over-gross ratio and Por = net-reservoir porosity.

Free hydrogen Gas-In-Place-per-unit-area (H_2GIP), in mass units, is calculated as:

$$H_2GIP = PV * S_g * H_2frac / B_{gi} * H_2den$$

where S_g = total (free) gas saturation including H_2 plus other gases, H_2frac = fraction of hydrogen in the gas, B_{gi} = gas-expansion factor for hydrogen at initial reservoir conditions (estimated from industry-standard equations, i.e., using pseudo-critical temperature and pressure for hydrogen to calculate a hydrogen gas-compressibility “Z” factor [20]), and H_2den = density of hydrogen at standard conditions.

In free hydrogen-gas systems, gascap expansion would be the dominant recovery mechanism unless there is a very strong, active aquifer connected to the hydrogen gascap. Recovery Factor would largely be a function of abandonment pressure relative to initial pressure. Assuming pure depletion, hydrogen recovery-potential can be estimated as follows. First, free H_2-gas-in-place-remaining-per-unit-area (H_2gRem), at depleted reservoir conditions in mass units, is calculated as:

$$H_2gRem = PV * S_g * H_2frac / B_{gr} * H_2den$$

where B_{gr} = gas-expansion factor for hydrogen at depleted reservoir conditions (estimated using industry-standard equations).

If a very strong and active aquifer is anticipated, aquifer pressure-support may limit gascap expansion and instead, reservoir “drive” may mostly come from water encroachment into the gascap. In such a situation it may be appropriate to modify the equation to calculate free H_2-gas-in-place-remaining-per-unit-area (H_2gRem), at depleted/watered-out reservoir conditions in mass units, to read:

$$H_2gRem = PV * S_{grw} * H_2frac / B_{gr} * H_2den$$

where S_{grw} = gas saturation residual to water (trapped, residual gas saturation at the imbibition endpoint which, for hydrogen-brine systems, may be around 30-35%; [23]). Note that pressure depletion may be minimal in case of a strong aquifer which means that $B_{gr} \approx B_{gi}$.

Free hydrogen-gas recovery-per-unit-area or “Recoverable Hydrogen Resource-Density” (H_2UR) can be estimated as:

$H_2UR = H_2GIP - H_2gRem$

3.2. Well Production Rates

A combination of analogue data and industry-standard petroleum engineering equations (e.g., pseudo-steady-state productivity of gas and water wells) have been used to estimate indicative well productivity for the case-studies analysed. Fluid- and reservoir-parameter input into these equations have been derived based on available reservoir, pressure and temperature data for the respective case-studies combined with industry standard correlations and estimation methods.

3.3. Water Production and other Byproducts

Water production rates associated with a hypothetical development of field-examples of the different plays, are estimated using material balance.

First, pressure depletion per-unit-of-water-extracted-per-unit-area (P_{depl}_per_rb) is calculated:

$$P_{depl}\_per\_rb = (1 / PV) / (C + C_f)$$

where PV = reservoir PoreVolume-per-unit-area, C = fluid compressibility and C_f = formation (rock matrix) compressibility. Compressibility values are calculated using industry-standard methods [44].

The anticipated amount of water-per-unit-area (VolWat) produced as a result of fluid lifting for hydrogen extraction, is then calculated:

$$VolWat = (P_i - P_r) / P_{depl}\_per\_rb / FVF_w$$

where P_i = initial reservoir pressure; P_r = depleted reservoir pressure; and FVF_w = formation-water volume factor (calculated using industry-standard methods [44]).

Note that estimates of produced water derived via this method are conservative in the sense that they assume there is no attached aquifer beyond the resource area itself.

Estimates of production-quantities of other gases (besides hydrogen) are made by considering the fraction of hydrogen in the gas (H_2frac, introduced as part of the resource assessment). Estimation of $UR_{othergas}$ (the volume of non-H_2 gases per unit area at standard conditions) is as follows:

$$UR_{othergas} = H_2UR / H_2den / H_2frac * (1- H_2frac)$$

where H_2UR = produced H_2 in mass units, H_2den = H_2 density at standard conditions.

3.4. Development-Project Metrics (well count and resource-area required for a certain amount of production)

Indicative development metrics i.e., well counts and resource-area size that needs to be developed for a certain amount of H2 supply, are anchored to the estimates of Hydrogen Resource-Density and well production rates made for each of the play-type examples.

The number of producer wells a Project must drill to achieve a contractual rate of H_2-Supply (e.g., a committed tonnage H_2 per year), can be estimated as:

$$\text{\#-of-Wells} = H_2 \text{ supply-commitment per year} / H_2 \text{ production-rate per well per year}$$

The amount of resource area a Project must develop to maintain H_2-Supply over a given contract-period, can be estimated as:

$$\text{Area (km}^2\text{)} = (\text{H}_2 \text{ supply-commitment per year} * \text{\# years}) / ([\text{H}_2\text{IP} + \text{H}_2\text{recharge} * \text{\# years}] * \text{RF})$$

where H_2IP =In-place H_2 resource density (H_2 per km^2); H_2recharge = H_2 recharge-rate per km^2 per year; and RF = H_2 Recovery-Factor.

Hydrogen recharge-rates are a subject of much speculation. [11] and [15] suggest "global" rates of hydrogen generation may range between 25Mt to 25,000Mt (million tonnes) per year which, considering the earth' surface area of 510 million km^2, works out to be between 0.05 to 50 ton/km^2/yr. Development-metrics calculations in this paper assume a base-case of no significant recharge (i.e., H_2recharge = 0). Whilst as an upside, a H_2recharge-rate of 50 ton/km^2/yr (upper end of the range proposed by [11] and [15]) is used to assess the potential improvement in development metrics.

This paper uses the different H_2 offtake-opportunities shown in Figure 1 as hypothetical "projects" to work out development metrics. For each "project", a contractual supply-commitment of 7 years is assumed (considered a reasonable minimum for a long-term Gas Sales Agreement; [24]).

4. Results

4.1. Hydrogen Systems and Play Types

Conceptually, working subsurface "hydrogen systems" comprise the same key elements as their "petroleum system" counterparts namely: Source, Reservoir, Trap and Seal [14][25]. However, petroleum systems occur in sedimentary basin-fills where vertical stacking of source rocks, multiple reservoir levels and sealing lithologies is common and where there is a tendency towards relatively high-relief but gentle structures capable of trapping large amounts of hydrocarbon. However, much of the suspected hydrogen sources are outside sedimentary basins and in settings where favourable conditions may be less common.

Assuming a location with one or more active hydrogen sources, effective trapping of hydrogen in the subsurface would then critically hinge on presence, around the same site, of 1) a reservoir rock with adequate storage capacity for hydrogen, either as a pore fill or (in the case of coals) adsorbed on a molecular scale; 2) presence of a seal rock with adequate tightness to hold the pressure differential of a trapped hydrogen-gas column [26]; and 3) a trapping configuration of reservoir and seal. In case of seal-breach, reservoir layers may still contain hydrogen but most of it will be in aqueous phase since residual quantities of H_2-gas in breached traps and H_2 gas-saturation in advective migration pathways [14] may be low. Reason being, critical gas-saturation (the saturation at which gas molecules become mobile) in H_2-brine systems is believed to be low due to the small molecule size and high volatility of H_2, consistent with the observed onset of H_2 mobility at very low gas saturation in relative permeability experiments [23][27].

One factor which is fundamentally different from hydrocarbon plays is preservation of hydrogen in traps: hydrogen is both chemically (with carbon and oxygen) and biologically active (e.g. methanogenesis) [28][29]. This effect is not taken into consideration here, but is another risk factor in the exploration for natural hydrogen.

Considering "success" or "failure" on the various play elements of the conceptual hydrogen system and consequences for technical development-potential, this paper proposes to categorize hydrogen "finds" and prospects into three broad hydrogen play-types:

1. "Focussed Seepage" plays where there is an active hydrogen source but limited (if any) subsurface trapping of gaseous hydrogen. In such systems, hydrogen concentrations may reflect localized migration pathways, mostly of dissolved hydrogen.
2. "Coal-Bed Hydrogen" plays where hydrogen is adsorbed on a molecular scale in coals. In such a system, top-seal and trapping configuration are not strictly required.
3. "Reservoir-Trap-Seal" configurations with a gaseous hydrogen column of significant length trapped underneath an impermeable seal, like in a conventional gas field.

Following paragraphs describe these different play-types in more detail from geology and development-potential perspective, illustrated with actual field examples.

4.2. "Focussed Seepage" Plays

This play-type model describes settings where there is active expulsion of hydrogen from one or more subsurface sources (e.g., hydrothermal serpentinization of ferroid rocks, deep-mantle degassing or radiolysis of formation water) with but limited (if any) trapping of hydrogen in gaseous phase. Without trapping, buoyancy forces drive the expulsed hydrogen upward where it will eventually leak out at surface. However, due to subsurface heterogeneity this migration will seldomly be uniform. Instead, structural features like folds and faults will typically funnel the expulsed hydrogen into discrete migration pathways such as fault/fracture zones or laterally extensive permeability "thief zones" like karst horizons. Where migration pathways outcrop, notable surface-seeps and corresponding surface expressions (e.g. fairy circles) may result. Hydrogen is believed to migrate mostly via advective flows [14] and where it migrates through relatively tight formations at slow rates and with long residence times, formation waters in and around migration pathways may be saturated with hydrogen alongside small amounts of residual H_2-gas. Consequently, wells intercepting such pathways may see hydrogen "gas shows" especially if the drilling is done at balance or underbalanced (as was reportedly the case at Bougou in Mali [3]). When pressure drawdown is applied (with a downhole sampling tool or during a flowtest), formation-water solubility of hydrogen reduces and some hydrogen will be released in gaseous phase and flow into the well. However, gas flowrates will typically be low and often hampered by water encroachment.

Recent research indicates that hydrogen fluxes from deep subsurface to atmosphere may be much more significant than what had been assumed before (e.g. [11][15]), and natural H_2 seeps may also be relatively common.

4.2.1. Field Example: Bougou Field (Mali)

The Bourakebougou (Bougou) field in Mali features the world's first hydrogen producer-well, Bougou-1 which production-tested 1,500m^3 a day (0.13 ton/day) of nearly-pure hydrogen from an interval some 60 to 112m below surface [28][3]. Following the test, Bougou-1 was used to supply a nominal 5 ton of H_2 per year to a power generator in the nearby village for a small non-commercial power project [2][31]. Subsequent appraisal wells showed that the reservoir produced by Bougou-1 is a karstified and fractured but otherwise rather tight dolomite stringer sandwiched in between dolerite sills (Fig. 2 and Fig. 3) [2][3]; this zone is called "Reservoir 1". The deeper stratigraphy down to granite basement consists of tight sandstones (3-6% porosity; some of it with gas shows but not flow-tested), some additional carbonates, some shales and additional dolerite sills. The structure is a gentle anticline that plunges to the north and is open to the south. Reservoir pressure down to basement appears to follow a hydrostatic trend [2].

It has been suggested [32] that a dolerite sill above "Reservoir 1" acts as an effective top seal for entrapment of hydrogen gas. However, our integrated review of all available open-domain data suggests that a large, connected gascap of significant height (exerting significant excess-pressure at the structure crest) in Bougou is extremely unlikely, for the following reasons:

1. Structure evidence, notably the absence of any relationship between the presence and intensity of gas shows and structure elevation despite some 80m of vertical relief (the elevation difference between the shallowest and deepest wells with gas shows; Fig. 2). No base-of-shows can be defined in the data. Also, the assumption of a continuous H_2 gascap across all wells on the structure (i.e. a gascap at least 80m high) would imply a pressure at the crest close to or in excess of lithostatic pressure;
2. Pressure evidence, notably the low shut-in pressure observed during the Bougou-1 welltest (61psia, [28]). Figure 3 shows an estimated Free Water Level by assuming a H_2 pressure-gradient in the Bougou-1 well (during shut-in, the head of the well would be filled with H_2 gas) and intercepting this with an aquifer-pressure-gradient based on regional groundwater data [33]. It then becomes evident that most of the reservoir must be in the water leg. A small hydrogen gascap may only exist in the uppermost few meters of the reservoir around the crest of the structure;
3. Petrophysical evidence, notably the neutron-density log signatures in the appraisal wells surrounding Bougou-1 (which itself was not logged). Across the entire "Reservoir 1" including the intervals with hydrogen mudlog-shows, the neutron response deflects towards higher neutron porosities (23 to 35p.u.) whilst the density log also reads high (2.55-2.75 g/cc), see Fig. 3 and Fig. 4. Density readings in "Reservoir 1" itself are reasonably consistent with a dolomite mineralogy (as recorded in core) albeit a bit low for the modest amount of porosity determined from core (on average 4.5%). The breccia directly above "Reservoir 1" appears to be a limestone. High neutron-porosity in the dolomite is not a gas response but rather related to lithology (presence of water-bearing minerals e.g., clays or diagenetic minerals related to hydrothermal alteration). If the pore-space of this dolomite would have been filled with H_2 gas, it would result in exactly the opposite effect: a lower neutron-porosity (due to the low Hydrogen Index of gaseous H_2 especially at low pressure) and a lower density (due to the low apparent density of H_2 gas especially at low pressure).

We therefore conclude that Bougou field is not a trapped accumulation of gaseous hydrogen but a wide leakage zone between the Taoudeni Basin to the north and the outcropping West Africa craton to the south. Its hydrogen is mostly dissolved in formation water and possibly originating from the banded ironstones within the craton complex. The karsted and laterally extensive "Reservoir 1" dolomite stringer provides an obvious migration flow-path within a succession of otherwise rather tight rocks. Whilst pressure and log data indicate that most of "Reservoir 1" is in the water leg, some very small crestal H_2 gascaps or "pockets" (e.g., isolated clusters of fractures with some gas-fill) may locally exist at the top of the dolomite and Bougou-1 may have intercepted one of these H_2-gas pockets. When the Bougou-1 well is flowing H_2 from this small, local gascap or pocket, some additional H_2 may release from the aquifer. A 26psi pressure drawdown as applied in the test [28] would nearly halve H_2 solubility compared to initial conditions and hence, in the pressure "sink" around the well, release significant amounts of aqueous H_2 into the gascap or pocket. H_2-gascap height (a few meters at most) is very small compared to the overall thickness and lateral extent of the reservoir which means that the ratio of aquifer-over-gascap porevolume is very large: a strong aquifer. This explains the notion [2] that pressures did not deplete since the start of Bougou-1 production: when producing from a small gascap connected to a very large aquifer, one would not expect much pressure depletion especially given the small H_2-volumes produced from Bougou-1.

Gas-shows locally observed in the deeper “Reservoirs 2 to 5” intersected by the Bougou appraisal wells [3] [2] are much less intense than the gas shows in the “Reservoir 1” fractured and karsted dolomite, possibly because of poor reservoir quality (sandstones with 3-6% porosity likely have a very low permeability). Shows in these deeper reservoirs are also mostly if not entirely from aqueous hydrogen since there is no indication (from neutron-density log expression or from pressure data) of free H_2-gas presence.

4.2.2. Technical Potential

This section discusses resource density, productivity and indicative “development-project” metrics of the Bourakebougou field, to illustrate the technical potential and issues pertaining to exploitation of “focussed seepage” plays.

Resource Density and Recovery Factor. Figure 5 lists the input parameters used to calculate Hydrogen-In-Place Resource Density for Reservoirs 1 to 5 in Bougou. Because the vast majority of reservoir-interval is waterleg whilst gascaps, if any, are very small and localized, the aqueous hydrogen method was used. Reservoir properties are based on well-log panels and core data presented in [2] and [32]. Assumption of hydrostatic pressure is based on data in [2] whilst reservoir temperatures are estimated using a 31degC surface temperature and a 15.6degC/km geothermal gradient taken from Bougou-6 and regional data [34]. Dissolved gas is assumed to be 98% H_2 like the Bougou-1 produced gas-composition [2] [3]. With these assumptions, an In-Place Resource Density (H_2IP, aggregated hydrogen-per-unit-area across Reservoirs 1 to 5) at Bougou is estimated at around 3,000 ton hydrogen-per-km^2 (Fig. 5)

To estimate amounts of potentially recoverable hydrogen, an “average” depletion across the entire resource area of 40psi is assumed. Rationale for this depletion assumption is as follows. For the shallow “Reservoir 1” dolomite stringer, 40psi depletion would lower reservoir pressure to near-atmospheric i.e., further depletion is not possible. The deeper reservoirs are at higher pressure but permeability is very low (low productivity makes it difficult to deplete large areas) whereas aquifer size could be substantial. Moreover, depleting individual zones differentially would require dedicated wells or some form of downhole control in commingled wells, which would increase cost. The uniform 40psi depletion across all reservoirs is consistent with a simple and minimum-cost well concept of commingled completion without individual zone control as depicted in Fig. 6.

A 40psi “average resource-area” depletion results in a “Recoverable Hydrogen Resource-Density” (H_2UR) for Bougou of around 150 ton hydrogen-per-km^2, a Recovery Factor of 5% (Fig. 5).

Production-rates per well. The observed range in flowrates in Bougou-1 is between 5 ton per annum (reported nominal production-rate) and 1,500 m^3/d (50 ton/year; the 1-day flowtest rate; Briere et al, 2017). However, Bougou-1 was not optimized for gas production (drilled as a water well the well may have a high skin) and it produces only from “Reservoir 1”. Figure 6 depicts some speculative improvements in well flow-rate, estimated using industry-standard techniques (pseudo-steady flow equations, assuming 50mD permeability in Reservoir 1 consistent with Bougou-1 flowtest and 0.1-1mD in the deeper zones). Tentatively, a low-skin, commingled multi-zone well as depicted in Figure 6 may be able to produce some 830kg H_2 per day (300 ton per year): 6 times the Bougou-1 test-rate. Note that to sustain this rate, individual wells must be able to effectively drain rather large areas as the Recoverable Hydrogen Resource-Density" (H_2UR) for Bougou is only around 150 ton hydrogen-per-km^2.

Water production and other byproducts. Estimates of anticipated water production are made using material balance. Assuming (conservatively) that aquifer size is limited to the resource area only, depleting the ca. 87.5 MMrb-per-km^2 of formation-water porevolume across Reservoirs 1 to 5 by some 40psi, would require lifting about 0.34MMstb of water-per-km^2.

Gas produced in Bougou-1 is reported to be nearly pure H_2 (98% of hydrogen, 1% of nitrogen and 1% of methane; [3]). Production and disposal of non-sellable gases would therefore not be an issue at Bougou.

Development-Project Metrics. Table 1 shows indicative development-metrics for a range of hypothetical development-projects at Bougou, calculated based on estimated in-place and recoverable H_2 resource-density, estimated H_2 well productivity and water production as described in previous paragraphs.

It can be seen that to achieve industrial-scale offtake maintained over a multi-year contract duration, many hundreds to thousands of producer wells would have to be drilled across thousands of km^2 of development area, many times the area appraised by operator Hydroma. Hundreds of millions to billions of barrels of water would be produced; handling, processing and evacuation or disposal of this water would be a major undertaking.

Development metrics for the local offtake-opportunity type projects appear less overwhelming but nevertheless, committing to several years of offtake would require drilling up areas larger than the appraised Bougou structure. Cumulative water production might be in the order of 20 to over 400 million barrels depending on the project size and again, water handling would be a significant task.

If a natural hydrogen recharge-rate of 50 ton H_2/km^2 per year is assumed (the high end of the "global" H_2 generation rates postulated by [11], size of the areas that require development to maintain H_2-supply throughout the contract period reduces by 10 to 17% depending on project scope and specifics (Table 1). Water production may also reduce by the same percentage. The initial producer-well count would not change because it is driven by offtake requirement versus well productivity, parameters that are unaffected by recharge.

4.3. "Coal-Bed Hydrogen" Plays

This play-type describes settings where hydrogen gas is adsorbed onto the molecular fabric of coal beds or other organic material. Coals can adsorb significant quantities of gas: they preferentially adsorb methane but they can also adsorb hydrogen. Experimental data [35] shows that the "isotherm curves" which describe adsorption capacity of hydrogen in coals increase with pressure and decrease with temperature (similar to methane and CO_2 isotherms). In principle, hydrogen adsorption in coals does not require structural trapping.

Hydrogen is not uncommon as a component of coal-mine gas; according to [11] the first discovery of natural hydrogen was in fact made in gas from a coal mine in Ukraine. Hydrogen usually occurs in proportions of less than 30% mixed with other gases, notably methane and CO_2.

4.3.1. Field Example: Lorraine (France)

Folschviller-1 in Lorraine (France) is a coal-bed-methane (CBM) test well where hydrogen shows were reported by operator France De Energie (FDE) [4]. Gas shows were detected in a succession of

Carboniferous coal beds of between 4 to 13m net thickness, sandwiched in between sandstones and shales [36] [37]. Because the depths of the gas-shows match depths of the coal beds (Fig. 7) and since the intercalated sandstones are completely tight (based on density-log response), gas appears to be adsorbed in the coal beds rather than stored as a pore fill. The gas is predominantly methane but hydrogen content increases with depth from some 6% H_2 at 760m to 20% at 1250m. Measured gas contents in the coal seams vary between 7 to 10m^3 per ton [36] which suggests the coals may be undersaturated. Reported permeabilities are between 0.5 to 4mD and declining with depth as is usual in CBM assets [38].

4.3.2. Technical Potential

This section discusses resource density, productivity and indicative "development-project" metrics for the Lorraine hydrogen-find, as an example of the technical potential and issues pertaining to exploitation of "coalbed hydrogen" plays.

Resource Density and Recovery Factor. Figure 7 lists the input parameters used to calculate Hydrogen-In-Place Resource Density for the six major coal seams identified in Folschviller-1 well. Coal-seam thickness, density and gas content are based on logs and tabulations released by European Gas Limited (EGL) and FDE [36] [37]; reported gas contents were taken as "Raw". Hydrogen fraction is based on FDE's press releases [4] and extrapolated (using the trend of increasing H_2 fraction with depth; Fig. 7) for seams without data. Using these assumptions, a total Gas-In-Place-per-unit-area (GIP, aggregated across all coal seams) is estimated at around 900 MMsm^3-per-km^2. In-Place Hydrogen Resource Density (H_2IP) is around 120MMsm^3-per-km^2 (13% of gross gas); in mass terms this equated to around 10,900 ton H_2-per-km^2.

Assuming a Recovery Factor (RF) of 50% (reflective of the optimistic end of CBM-analogues [39], Recoverable Total Gas (GasUR) in Folschviller may be around 450MMsm^3-per-km^2 whilst recoverable hydrogen resource-density (H_2UR) might be around 60MMsm^3/km^2; in mass terms 5,400 ton H_2-per-km^2.

Production-rates per well. Rates per well have been estimated based on analogue developments and anchoring to the resource-density and distribution observed within the Folschviller-1 well.

First, considering that individual coal seams in Folschviller are relatively thick (several meters) with many tens of meters of interburden in-between (Fig. 7), development wells would likely target individual seams (e.g. multi-lateral in-seam wells). This well design would give a more effective depletion (consistent with the high RF assumed) compared to commingled wells. Second, effective depletion of these modest-permeability seams may require a relatively high well density, possibly in the range of 500m spacing (i.e. 4 wells per km2; cf., [40] [41]), again consistent with the relatively optimistic assumption of 50% RF. Hence, a development of Folschviller may involve some 24 producer-wells per km^2 of resource area (6 seams, 4 wells per seam per km^2).

Gross Gas Recovery-per-well can then be estimated as follows: GasUR-per-km^2 / #wells-per-km^2 = 450 / 24 = 19MMsm^3, of which 2.5MMsm^3 (226 ton) H_2.

Then, considering that in CBM wells a typical plateau duration might be around 3 years and 50% of the well UR may be produced on plateau, plateau-rate of a Folschviller producer-well could be in the order of 0.5 * 19 / (3*365) = 8.6Mm^3 per day (300Mscf/d) of gross gas; in line with similar CBM developments [38]. Hydrogen plateau-production may be around 1.2Msm^3 per day-per-well or 40 ton per year-per-well.

Water production and other byproducts. Estimates of anticipated water production are made using material balance. Whilst initial (hydrostatic) reservoir pressure ranges from 1,100psi in the shallowest coal-seam to 1,800psi in the deepest seam, it is assumed that continued fluid lifting to depressurize and desorb gas from the coals may eventually deplete reservoir pressures to around 300psi. Reported porosity from Lorraine coal samples is around 6% [42] which, combined with the seam thicknesses shown in Figure 7, indicates a coal-seam PoreVolume per km^2 of around 24MMrb. Assuming a coal compressibility of $6.8*10^{-7}$ [43] and water compressibility estimated based on pressure and temperature via McCain correlation [44], material-balance suggested water production per km^2 is around 0.34MMstb. Which, assuming 24 wells per km^2, equates to around 14Mstb per well.

Only some 13% of the producible gas in Folschviller would be hydrogen, the remaining 87% is predominantly methane [4]. To successfully commercialize hydrogen as a sales product by itself, it would have to be separated from methane into a H_2 sales-stream of sufficient purity.

Development-Project Metrics. Table 2 shows indicative development-metrics for a range of hypothetical development-projects at Folschviller, calculated based on estimated in-place and recoverable H_2 resource-density, estimated H_2 well productivity and water production as described in previous paragraphs. Thanks to a relatively high resource density (considerably higher than at Bougou), the resource-areas that would need drilling up to commit to commercial offtake over number of years, are relatively modest in size. But because well productivity is low, many hundreds to several thousands of development wells would have to be drilled to reach the required offtake levels. Only the smaller local-offtake opportunities can be supplied with less than hundred wells. Water production would be less than for the "focussed seepage" playtype (Bougou) but still considerable especially for "industrial-offtake" scale projects. Handling and evacuation or disposal of this water would add project complexity and cost. Hydrogen recharge has a negligibly small impact on development metrics because the resource density is high compared to the possible rate of recharge.

4.4. "Reservoir-Trap-Seal" Plays

This play-type model describes settings with an active hydrogen source combined with a favourable trapping configuration involving one or more porous and permeable reservoirs capped by seals that can hold the pressure differential of a column of gaseous hydrogen. Existence of such systems, analogous to conventional gas fields [14], for now remains a speculation awaiting exploration confirmation. Despite numerous reports of hydrogen seeps at surface and traces of hydrogen in the subsurface [9] [6], none of these finds convincingly demonstrate the presence of hydrogen trapped in a porous and permeable reservoir, in gaseous phase and at excess pressure.

4.4.1. Field Example: Monzon Prospect (Spain)

The Monzon prospect in Aragon [45] [46], is used here to illustrate the potential of a trapped accumulation of gaseous hydrogen, albeit speculative at this stage. The structure consists of a faulted, basement-cored anticline [46]. The main target reservoir is the Triassic Bunter sandstone (at 3600m, average porosity around 10%) which is sealed by an 1800m thick interval of evaporites and shales. Presence of storage-quality reservoir and a competent top-seal appear evident from the well data whilst available 2D seismic gives good indications of the possible presence of a valid trap. A 1963 exploration well (Monzon-1), drilled on the SW flank of the anticline (Fig. 8), recorded some hydrogen gas-shows in the Bunter but presence of free gas remains ambiguous from available logs and other data.

4.4.2. Technical Potential

This section discusses resource density, productivity and indicative "development-project" metrics for the Monzon Prospect (under the *specific* assumption of a "hydrogen gas-field success outcome"), as an example of the technical potential and issues pertaining to exploitation of "reservoir-trap-seal" plays.

Resource Density and Recovery Factor. Figure 8 lists the input parameters used to calculate Hydrogen-In-Place Resource Density for the Bunter reservoir in Monzon. Assumptions on reservoir thickness, properties (porosity and water saturation) and speculative presence of a 60m hydrogen column in the trap (height measured from crest to the Gas Water Contact) are based on petrophysical analysis of the Monzon-1 well logs [45] and regional data (reservoir pressure and temperature to compute gas Formation-Volume-Factor). A nearly-pure H_2 gas fill (98% of total gas) is assumed as per the interpretation of Monzon-1 mud-gas data [46]. Free H_2-gas per unit area is calculated with the method described in Section 3.1.3. For completeness, added to this are the (much smaller) amounts of H_2 that may be dissolved in the water leg and in capillary-trapped water of the gasleg; these quantities are estimated using the method described in Section 3.1.1. Use of these methodologies and assumptions results in a prospective Hydrogen-In-Place Resource Density (H_2IP) at Monzon of around 455 MMsm^3-per-km^2 or in mass terms, 43,000 ton H_2-per-km^2.

Assuming a pure depletion drive (i.e. a weak, inactive aquifer) and an abandonment pressure of 850psi, prospective Recoverable Hydrogen Resource-Density (H_2UR) at Monzon may be around 385MMsm^3 per km^2 or in mass terms, 35,000 ton H_2-per-km^2 (Figure 8); a Recovery Factor of 81%.

Production-rates per well. Indicative production-rates-per-well for a "hydrogen gas-field" outcome at Monzon have been estimated based on natural gas-field analogue practices. Assuming that a reasonable well-spacing could be around one well-per-km^2 [47] [48], that wells may produce 5 years at their plateau design-rate and that 80% of the gas Ultimate Recovery (i.e. around 300MMsm^3) may be produced at plateau, gas plateau-rate-per-well could be around 170Msm^3 per day (6 MMscf/d); some 5,500 ton H_2-per-well-per-year. Calculations using pseudo-steady-state gas flowrate theorem confirm that even a small-diameter (6") vertical well with modest drawdown (a few 10s of Psi) should be able to achieve 6MMscf/d gas offtake as long as reservoir permeability is at least a few 10s of mD. Alternative well designs (e.g., larger wellbore diameter, horizontal wells) could possibly achieve much higher offtake-per-well but economic viability of such more complex and costly well concepts would obviously depend on the field resource-size, on commercial demand and on offtake capacity of the evacuation system.

Water production and other byproducts. Under the assumption of a gascap of reasonable thickness (allowing perforations in producer wells to have some standoff from the Gas-Water-Contact) and a weak, inactive aquifer, no significant water production would be expected.

Similarly, in an outcome where Monzon is found to have a gascap consisting of nearly-pure hydrogen, production (and possible disposal) of non-hydrogen gases would not be an issue.

Development-Project Metrics. Table 3 shows indicative development-metrics for a range of hypothetical development-projects at Monzon, calculated based on estimated in-place and recoverable H_2 resource-density, estimated H_2 well productivity and water production as described in previous paragraphs. Evidently, a Monzon "hydrogen gas-field of high purity" success outcome may be able to supply H_2 to industrial facilities with a manageable number of wells, and sustain supply for a number of years. Supply to a large facility (e.g. an ammonia plant), however, would require a sizable gas field (~ 58km^2 area –gas

UR of around 22Bm^3). Hydrogen recharge has a negligible impact on development metrics because the resource density is very high compared to the possible rate of recharge.

4.4.3. Sensitivity

This section considers some alternative subsurface outcomes for Monzon that still imply hydrogen presence in the structure but in smaller quantities and in more challenging settings. Hydrogen resource-density, well production-rates and production of water and other byproducts have been estimated for these alternative outcomes in a similar manner as for the reference case, to illustrate sensitivity of the resource equations and the indicative impact on exploitation attractiveness. These also show the need for appraisal activities to reduce subsurface uncertainty and risk. Alternative Monzon subsurface-outcomes considered here are:

1. A free gascap of same dimensions as the "reference case" of previous paragraph, but with a much lower H_2-content of the gas (30% instead of 98%);
2. A smaller gascap (20m instead of 60m height measured from crest, avg. net gas-pay 10m instead of 30m) above a strong, active aquifer;
3. Aqueous H_2 only (no gascap).

Table 4 summarizes some of the key Resource Metrics for these alternative outcomes compared against the "reference-case outcome". The following observations are made.

For the "large free gascap with H_2 mixed with other gases" outcome, gross gas resource is the same as in the reference case but net H_2-yield is less than 1/3rd. Well-count would need to be tripled to achieve the same H_2 offtake. For the same H_2 production, gas processing-capacity would need to be much larger compared to the reference case and separating H_2 from the other gases would be more involved and costly. If the non-H_2 gases are non-sellable (e.g., CO_2 or N_2), disposal of these gases would add further complexity and cost.

For the "smaller gascap" outcome with large, active aquifer, Gas-In-Place resource density is smaller (60% of the reference-case) but more importantly, Recovery Factor drops to 31% only (vs. 81% in the reference) because the aquifer combats deep reservoir depletion and residually traps a lot of gas at high pressure. Consequently, H_2 Recovery is only 1/5th of the reference case. Reduced well productivity is reflective of shorter completion intervals (lower net) and lower drawdown to mitigate water coning. Wells may produce significant quantities of water in later life (Table 3 assumes a Water-Gas-Ratio of 1stb/Mscf for the final 20% of gas production).

For the "aqueous H_2 only" outcome (H_2 dissolved in formation water without a free gas-cap), In-Place Resource Density reduces to some 14% of the reference outcome. But more significantly, recovery potential reduces to some 100 ton H_2-per-km2 only (compared to 34,000 ton H_2/km^2 in the reference outcome) due to the difficulty involved in depleting aquifer pressures; a Recovery Factor of just 2%. Moreover, material balance calculations suggest that to achieve this recovery some 31 MMstb of water per km^2 of resource area would have to be lifted from the wells and subsequently handled at surface, (processed and then evacuated or disposed).

5. Discussion

The case-studies shown in this paper illustrate the differences in development potential for the different "natural Hydrogen Play-Types".

5.1. Development Potential of "Focussed Seepage" Plays

In "focussed seepage" plays, predominance of aqueous rather than gaseous hydrogen leads to a modest Hydrogen-In-Place resource density but also a low Recovery Factor because of the relative inefficiency of the recovery mechanism (reservoir depletion via lifting of water, to release H_2 from solution and to remobilize some of the residual H_2-gas). Hydrogen production-rates per well are also low, again because of the inefficiency of the recovery mechanism, and rates may be difficult to scale up especially in fields where the H_2-resource is spread across multiple reservoir zones. To progress towards commercialization of a "focussed seepage" find, high priority should be on flow-testing appraisal wells to establish whether commercial rates can be achieved.

Because of the predominantly aqueous nature of "focussed seepage" plays, inevitably large volumes of water will be co-produced with the hydrogen unless offtake is limited to wells targeted at localized crestal gas-caps or "pockets" like the Bougou-1 producer. However, since localized gas-caps will be small in size and may be difficult to locate, such a targeted development would only develop a small portion of the resource with a very modest offtake. A "resource-play" style of development with dense grid drilling of low-cost wells could facilitate the depletion of larger areas. In confined aquifer-settings (where there is no significant aquifer extent beyond the resource area itself) it will be easier to deplete pressures effectively with less water production compared to producing aqueous H_2 from large regional aquifers. Producing large volumes of water from a "focussed seepage" H_2 development may not be an issue in dry areas like Mali where water is a precious resource; in fact, it could add project value as long as the water can be handled at surface and processed to irrigation or drinking quality. But in geographic regions where there is no demand for large volumes of water, in regions with strict regulations with regards to aquifer depletion or in settings where produced formation-water is totally unsuitable for consumption, water handling and disposal could add substantial complexity and cost to a "focussed seepage" H_2 development.

Active hydrogen recharge could help reduce the size of resource areas that need drilling-up to sustain long-duration production but recharge does not affect the initial well-count required to meet a commercially committed offtake-rate for a project. Published estimates of global hydrogen recharge [11] [15] are relatively small compared to the estimated In-Place Hydrogen resource-density of the Bougou "focussed seepage" play which suggests that the impact of hydrogen recharge on the metrics for notional development "projects" may be limited. One could argue that in "focussed seepage" areas, higher recharge rates could be encountered but the 50 ton per annum per km^2 used as a "resource-area average" in this study is already substantial. In the Bulqizë chromium mine in Albania (situated in the Bulqizë Jurassic ultramafic massif), a series of mine shafts intersecting a large faultzone were found to vent a cumulative 200 ton of H_2 per annum [5], four times the recharge rate assumed in our study. Extreme seepage rates like seen in Bulqizë may be encountered locally around faults in a setting with abundant serpentinization potential but unlikely as an average over resource areas of many tens of km^2. Developments of "focussed seepage" plays would have to drill many tens or hundreds of wells to achieve commercial offtake and it is quite possible that some individual wells (e.g. wells drilled close to faults) receive substantial recharge. But for the development project as a whole, recharge is unlikely to make a material impact. In any case, development metrics calculated on the Bougou case for several hypothetical development "projects" (Table 1) suggest that only local-offtake opportunities might be pursuable. Unrealistically large well counts and water-handling/disposal capacity would be needed to meet industrial-size offtake.

It should be noted that gas in the Bougou example is of exceptional purity (H_2 content of 98%). Lower purity would proportionally reduce the already marginal Hydrogen Resource-Density and with the added cost of surface separation of H_2 from other gases and (if the other gases are non-sellable like CO_2 or N_2), disposal of those gases, commercial viability of a development would become even more challenging. Even if the other gases would be sellable, their environmental impact (e.g. Green-House-Gas emissions in case of CH_4) would have to be considered as this would reduce the attractiveness of the development project as a whole from a sustainability and low GHG-emissions perspective. On the other hand, Helium is frequently associated with natural H_2 [7][49] and provided quantities are sufficient, Helium extraction could add value to a development.

Finally, the very high well counts and large water-handling/disposal facilities required in "focused seepage" plays to meet industrial-size offtake, come with their own energy needs to manufacture, install and operate. These would take away a significant portion of the energy benefits from the white hydrogen produced by such projects.

5.2. Development Potential of "Coal-Seam Hydrogen" Plays

The Lorraine case demonstrates that in "coal-seam hydrogen" plays, Hydrogen-In-Place Resource Density can be substantial thanks to the large gas-adsorption capacity of coals. Gas Recovery potential can also be good, better than in "focussed seepage" plays as long as drilling is dense enough (to depressurize the coals efficiently). However, CBM production analogues suggest that well productivity in "coal-bed hydrogen" will be low due to the low permeability of coals, especially at larger depth (permeability declines with depth and the productivity floor may be around 1,200 m below surface; [38]). Moreover, to depressurize the coals enough to desorb material quantities of gas, large quantities of water will have to be lifted from the wells and handled and disposed at surface. Finally, hydrogen fraction in the total adsorbed gas may be low (as it is in Lorraine) due to the much higher adsorption capacity of gases like CO_2 and CH_4 compared to H_2. Techniques to separate hydrogen from other gases (especially CH_4) are a topic of ongoing research [49] [51] and to generate a sales stream of sufficient H_2-purity could be challenging and costly [52]. Volumes of CH_4 produced alongside H_2 could be commercialized but producing and selling natural gas would bring about a substantial GHG footprint for the project as a whole. In the case of Lorraine for example, CH_4 volume is eight times the H_2 volume and it would be hard to portray such a gas development as a "low-emissions project" aligned with net-zero targets.

Development metrics calculated on the Lorraine case for several hypothetical development "projects" (Table 2) suggest that only local offtake opportunities might be pursuable. Unrealistically large well counts would be needed to meet industrial-size offtake. Unlocking the development potential of "coalbed hydrogen" finds would require addressing the flurry of environmental concerns that have hampered CBM developments around the world e.g., water, surface footprint [38] [53]. Similarly to the "focussed seepage" plays, "coal-bed hydrogen" plays also require very high well counts and large water-handling/disposal facilities to meet industrial-size offtake. Energy needs to manufacture, install and operate all this equipment may take away a significant portion of the energy benefits from the white hydrogen produced by such projects.

5.3. Development Potential of "Reservoir-Trap-Seal" Plays

The Monzon case demonstrates that "reservoir-trap-seal" plays can have a very high Hydrogen-In-Place resource density if the hydrogen purity is high. Also, due to the much higher effectiveness of gas-cap expansion compared to other recovery mechanisms, Recovery Factor can also be high (up to 80% or more depending on initial pressure and availability of compression) unless the gas-cap height is very small and/or aquifer-influx is strong. Well productivity may also be high if the reservoir has some meaningful permeability (Monzon "reference-case" assumes 65mD and a very modest 20psi drawdown). Development metrics calculated for the Monzon reference-case for several hypothetical development "projects" (Table 3) suggest that industrial-scale offtake could be pursued with a few tens of producer wells. However, to commit long-duration supply to a large industrial facility like an ammonia plant, the resource area (i.e., the gas accumulation) would have to extend across several tens of km^2 unless reservoir thickness and properties are much better than at Monzon.

Sensitivities runs of the Monzon case (Table 4) show that if H_2 occurs mixed with other gases (the "reference outcome" assumed nearly-pure hydrogen), achieving large offtake-rates of hydrogen quickly becomes very challenging because large volumes of gas need to be produced for a modest hydrogen-yield. If the gas column is small and the aquifer strong, development metrics also deteriorate very significantly. A Monzon outcome with aqueous hydrogen instead of a gascap has very poor development potential due to low hydrogen productivity and large water production. This contrast shows how critical it is to confirm presence of hydrogen as a free gas as opposed to hydrogen dissolved in formation water.

Since "reservoir-trap-seal" plays appear the only play type that can meet the requirements of large industrial facilities, natural hydrogen exploration-efforts should focus on this type of play to make a material impact on global decarbonization. Gathering extensive reservoir and fluid datasets, especially reservoir pressures and flow testing, in hydrogen exploration/appraisal wells will be key to confirm 1) presence of H_2 as a free gas, 2) the height of H_2 gas-columns and 3) H_2-purity of the gas.

Conclusions

The three broad "hydrogen play-types" recognized in this paper namely 1) "focussed seepage"; 2) "coal-bed hydrogen"; and 3) "reservoir-trap-seal" systems, have very different development potential.

In "focussed seepage" play-type which may be relatively common, H_2 occurs predominantly in aqueous form (dissolved in formation water) with only small and localized gas caps. Development metrics estimated for the Bougou find in Mali indicate a modest Hydrogen-In-Place Resource Density, low Recovery Factor, low well productivity and high associated water production that may typify "focussed seepage" plays under a development scenario. Only local-offtake opportunities might be pursuable since unrealistically large well counts and water-handling/disposal capacities would be needed to meet industrial-size offtake. Active hydrogen recharge could help reduce the size of resource areas that need drilling up for a long-term supply commitment but based on resource calculations for the Bougou example, the impact of H_2-recharge on notional "development-project metrics" appears limited.

In "coal bed hydrogen" plays like the Lorraine H_2-find in France, Hydrogen resource density can be substantial thanks to the large gas-adsorption capacity of coals. Unfortunately, well productivity is low due to the low permeability of coals especially at greater depth. Moreover, "coal-bed hydrogen" plays may typically have a low H_2 content of the adsorbed gas (like in the Lorraine case) because of preferential adsorption of CO_2 and CH_4 and the preponderance of these in a coal environment. As a result, developments of “coal bed hydrogen” may require very high well counts for relatively modest offtake levels of H_2 whilst isolating a H_2 sales-stream of sufficient purity could be challenging and costly. Unlocking the development potential of “coalbed hydrogen” finds would require addressing the flurry of environmental concerns pertaining to CBM developments (e.g., water, surface footprint), and the optics of significant co-production of CO_2 and/or CH_4 in pursuance of white hydrogen. Even then, only local offtake opportunities might be pursuable.

“Reservoir-Trap-Seal” plays with a gaseous hydrogen column of significant length trapped underneath an impermeable seal, like in a conventional gas field (i.e. a “hydrogen gas field”), have the best development potential thanks to a combination of superior Hydrogen-In-Place resource density, high Recovery Factor and high well productivity. Development metrics calculated for the Monzon prospect in Spain demonstrate that “reservoir-trap-seal” finds may have the potential to meet industrial supply needs. However, a tendency for short gas columns (suppressing Recovery Factor and well productivity) and low H_2 content in the gas could create significant downside and limit the development potential of such finds.

In summary, based on the analysis made in this paper only “reservoir-trap-seal” plays may have the hydrogen resource-density and productivity to meet the requirements of large industrial facilities and hence, make a material and meaningful impact on global decarbonization. Unfortunately, to date no convincing examples of hydrogen trapped in gaseous phase, at excess pressure in a porous and permeable reservoir have been presented. This may be due to hydrogen’s ease of leakage and/or its reactivity (chemical and biological). Natural hydrogen exploration-efforts should nevertheless focus on this type of play, to demonstrate whether or not it exists.

Acknowledgements

Discussions with many individuals of the emerging “natural hydrogen community” on LinkedIn, at conferences and otherwise have stimulated our thinking and helped shape the concepts and theories in this paper. Bernard Van Dijk (Hydrogen Science Coalition) provided expert advice on the Hydrogen demand-assumptions for speculative local offtake. Chris Atkinson (Helios Aragon) and Tony Lawrence (TDL International) proofread earlier versions of this manuscript and their helpful comments are sincerely acknowledged.

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Figure Captions

Figure 1: Hydrogen Demand for typical Existing and speculative Future Industry Applications.

Figure 2: Top Reservoir-1 structure-map (left) and schematic cross-sections (right) illustrating the distribution of gas shows across the structure of Bougou Field (Mali).

Figure 3: Reservoir-1 pressure interpretation for Bougou field (Mali).

Figure 4: Neutron-Density plot for Reservoir-1 in Bougou field (Mali). Data is from well Bougou-8 (same well as Figure 3).

Figure 5: Reservoir Parameters and estimates of In-Place and Recoverable H_2 Resource-Density in Bougou Field (Mali).

Figure 6: conceptual design for a multi-zone aqueous-H_2 producer well in Bougou Field (Mali).

Figure 7: Reservoir Parameters and estimates of In-Place and Recoverable H_2 Resource-Density for the Folschviller "coal-bed hydrogen" H_2 find (France).

Figure 8: Reservoir Parameters and estimates of In-Place and Recoverable H_2 Resource-Density for the Monzon prospect (Spain) under the assumption of a "H_2 gas-field" outcome.

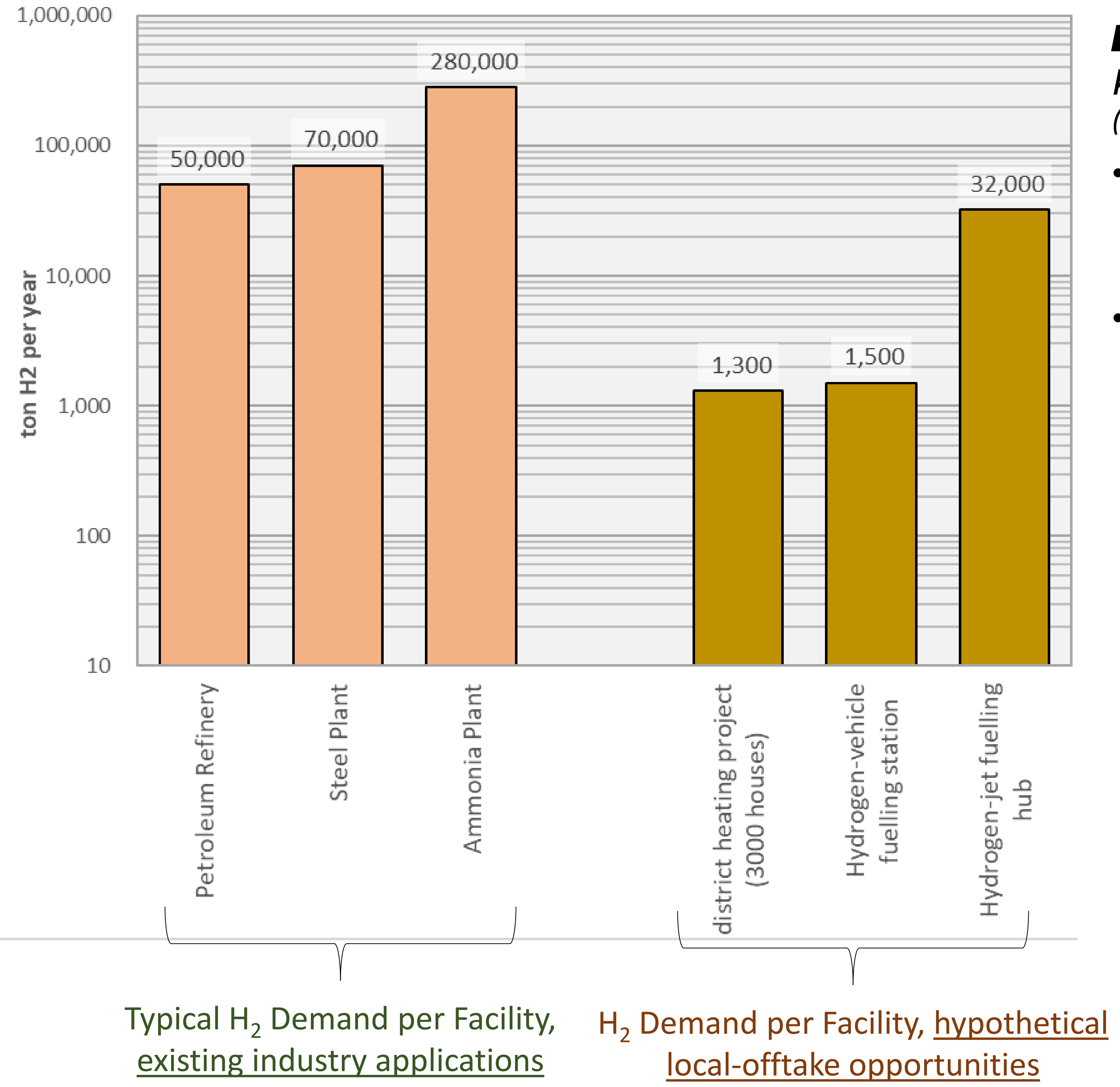
Table Captions

Table 1: Development metrics calculated for a number of hypothetical H_2 development "projects" at the Bougou field (a "focused H_2 seepage" in Mali).

Table 2: Development metrics calculated for a number of hypothetical H_2 development "projects" at Folschviller "coal-bed-hydrogen" find (France).

Table 3: Development metrics calculated for a number of hypothetical H_2 development "projects" for the Monzon prospect (Spain) under the assumption of a "H_2 gas-field" outcome.

Table 4: Comparison of key resource metrics for alternative prospect subsurface-outcomes at Monzon (Spain).



Existing Large Industrial Facilities

Key Decarbonization Targets

(source: Statistica, IEA)

- Average-size Petroleum refinery: 50kt/yr;
  Steel plant: 70kt/yr;
  Ammonia plant: 280kt/yr
- Petroleum Refineries and Ammonia Plants account for about 90% of current H_2 demand (90 million ton in 2023, of which <1% "green" H_2)

Hypothetical Local-Offtake Opportunities

Not necessarily desired from energy-efficiency viewpoint

- District heating project: 3,000 houses, 4,700 m^3 H_2 per house per annum (heating equivalent of 3,000 m^3 natural gas)
- Vehicle fuelling hub: 600 cars per day (filling up 4kg H_2 per vehicle) + 50 lorries per day (filling up 23 kg H_2 per vehicle)
- Jet fuelling hub: 10 jets per day, 8,800 kg H_2 per jet

Figure 1

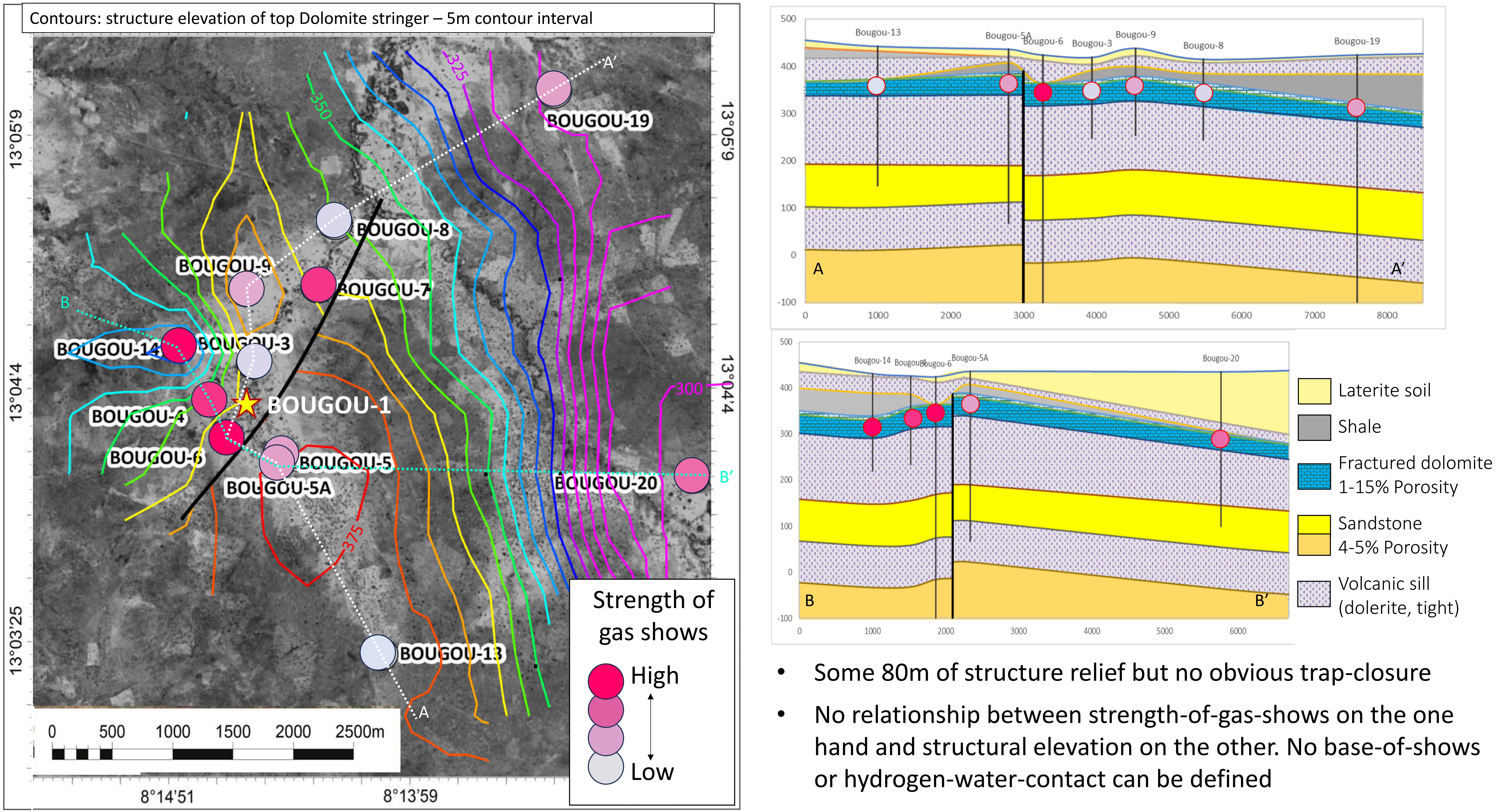
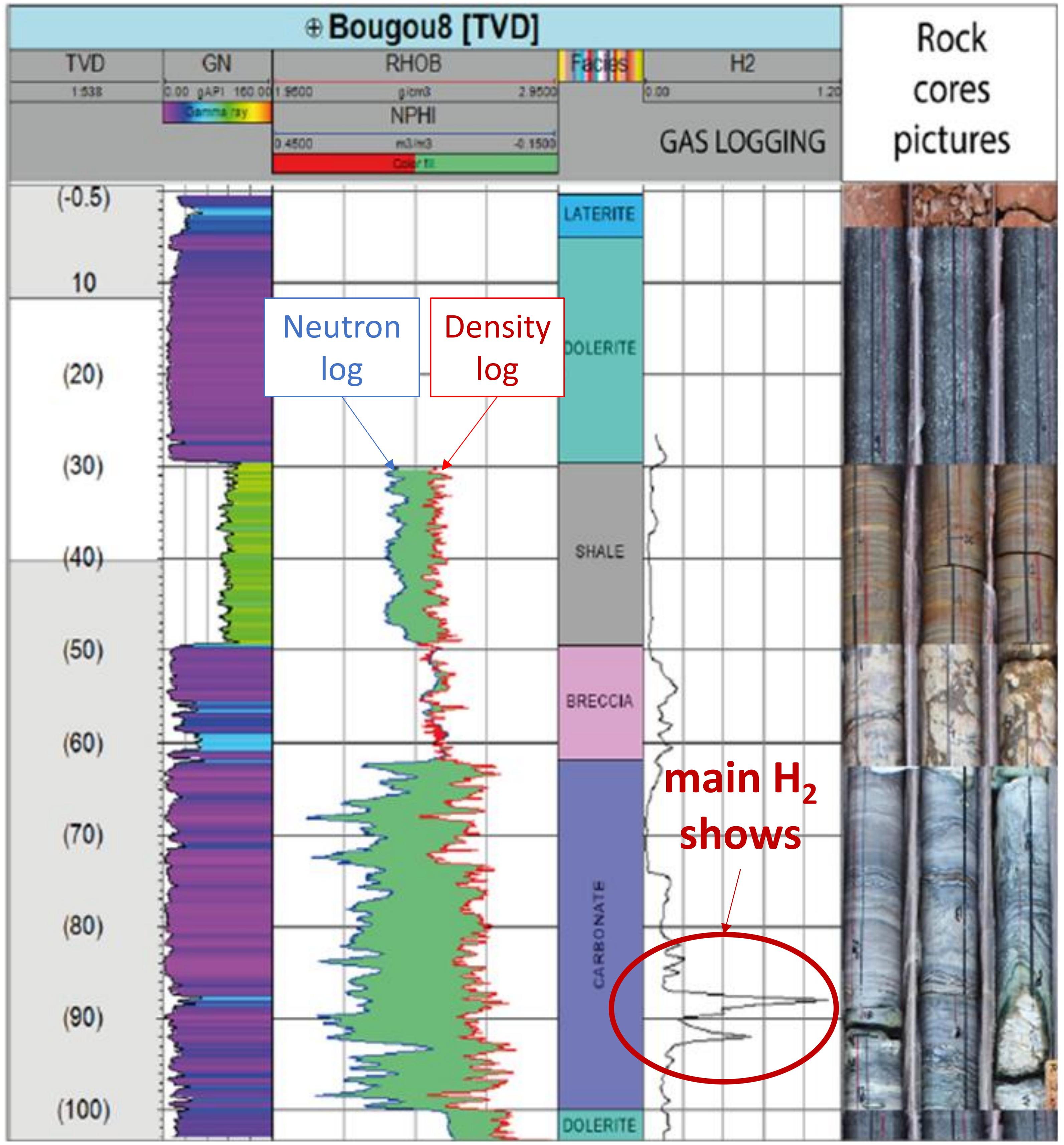


Figure 2

- Some 80m of structure relief but no obvious trap-closure
- No relationship between strength-of-gas-shows on the one hand and structural elevation on the other. No base-of-shows or hydrogen-water-contact can be defined

Bougou-8 (nearby offset well) log and core data (Maiga et al, 2023)



Bougou-1 (H_2 producer) pressure data from welltest (Briere et al, 2017)

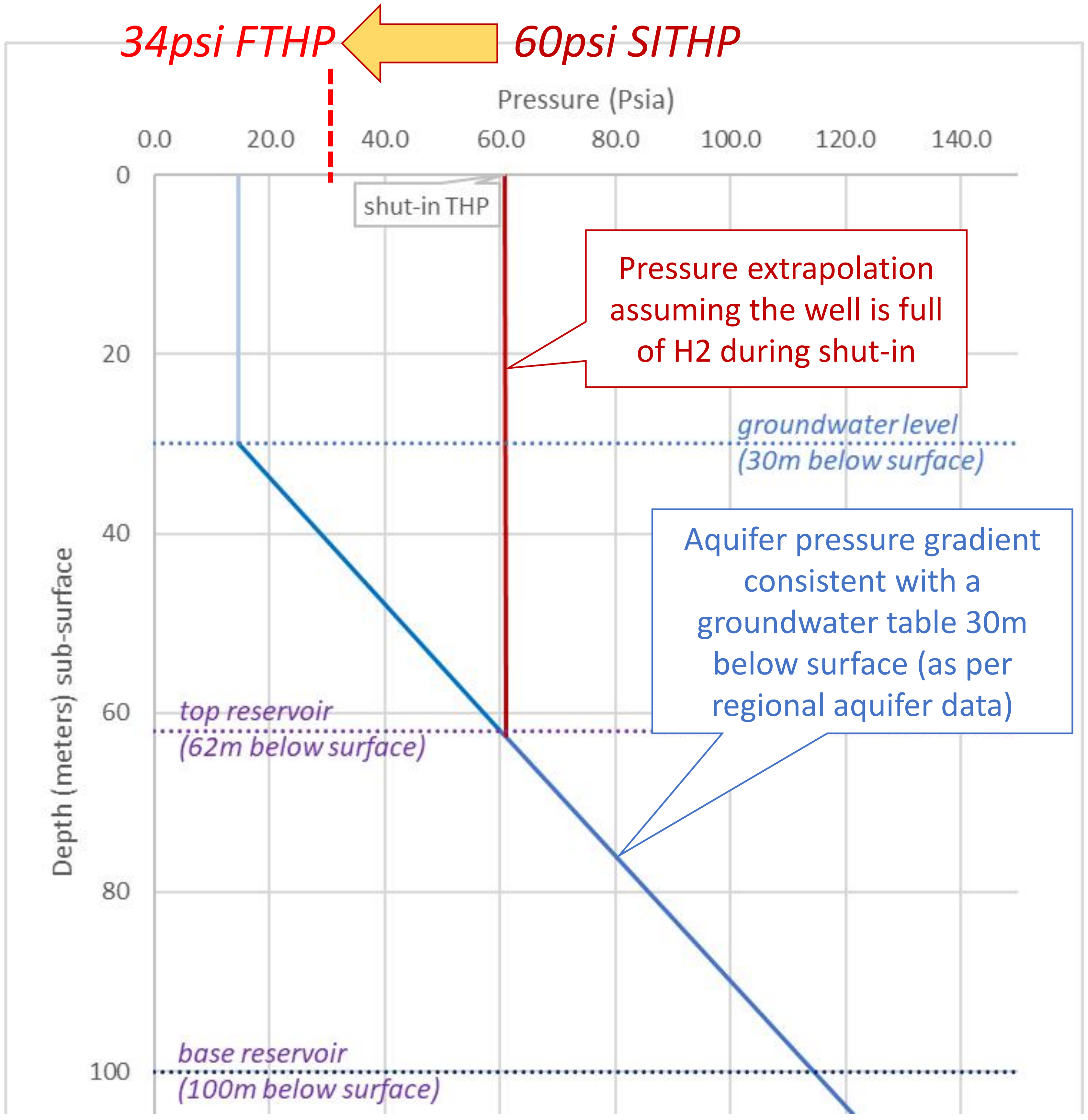


Figure 3

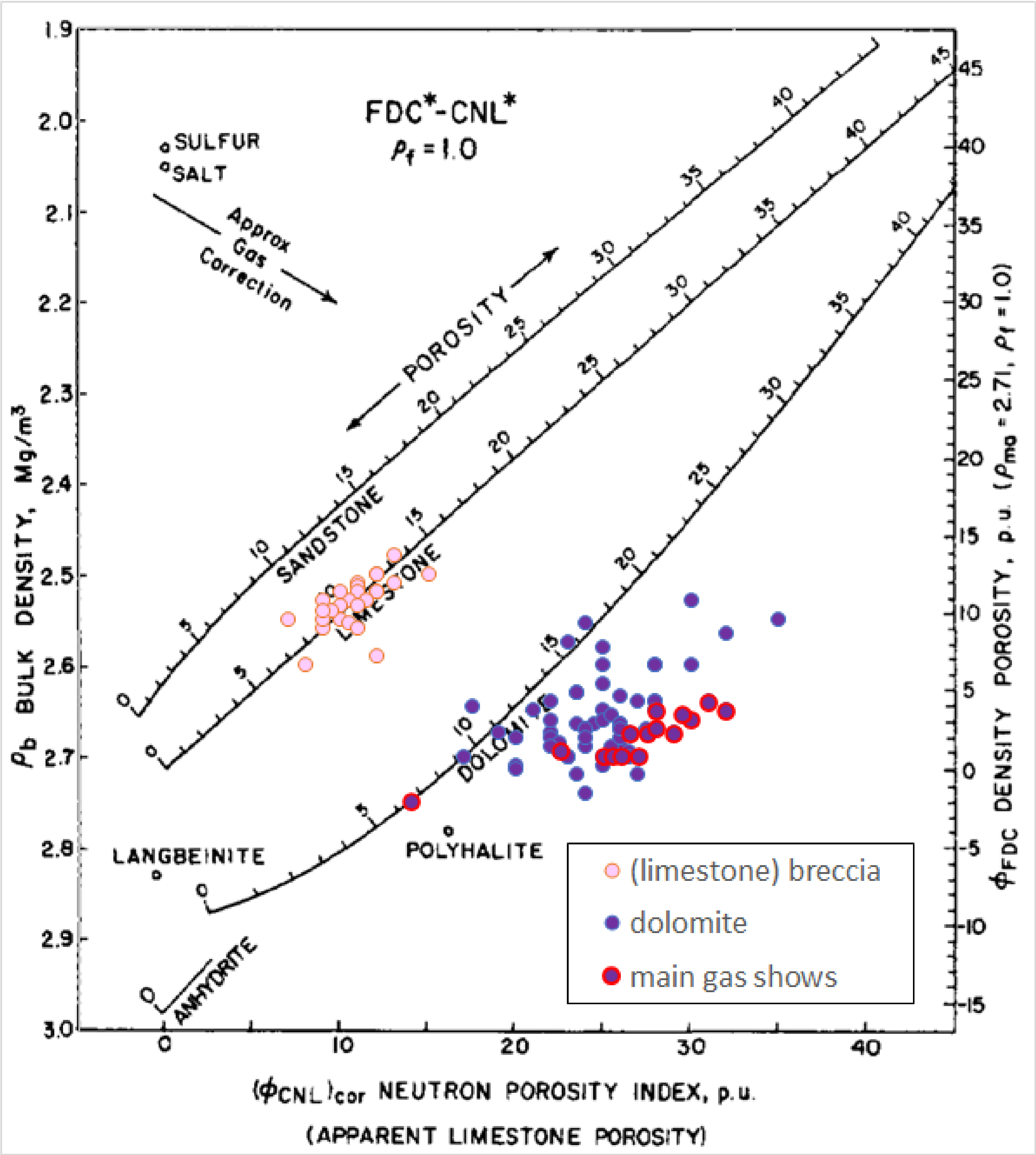
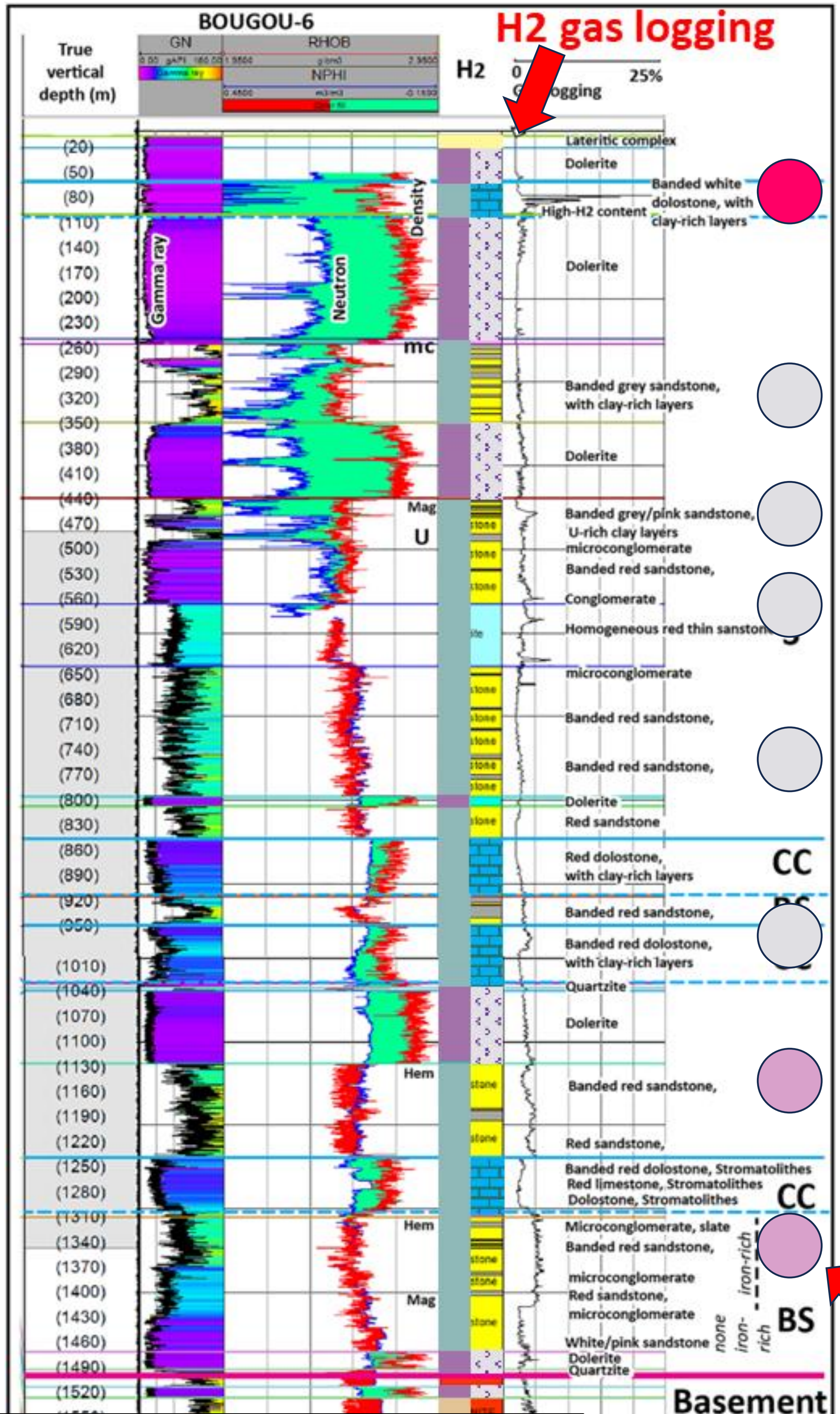

FDC*-CNL*
ρ_f = 1.0
SULFUR
SALT
Approx Gas Correction
POROSITY
SANDSTONE
LIMESTONE
DOLOMITE
LANGBEINITE
POLYHALITE
ANHYDRITE
ρ_b BULK DENSITY, Mg/m³
$(\phi_{CNL})_{cor}$ NEUTRON POROSITY INDEX, p.u.
(APPARENT LIMESTONE POROSITY)
ϕ_{FDC} DENSITY POROSITY, p.u. (ρ_{ma} = 2.71, ρ_f = 1.0)
(limestone) breccia
dolomite
main gas shows

Figure 4



Modified after Maiga et al (2023)

Reservoir	Net	Porosity	Pressure	Temperature	H2 In-Place	*H2 Recoverable*
	m	frac	psia	degC	ton/km2	*ton/km2*
1	15	0.08	61	32	20	*10*
2	45	0.06	343	35	250	*30*
3, 3a	148	0.05	700	39	1,230	*70*
4	54	0.03	1,585	49	650	*20*
5	36	0.05	1,842	51	830	*20*
TOTAL					**2,980**	***150***

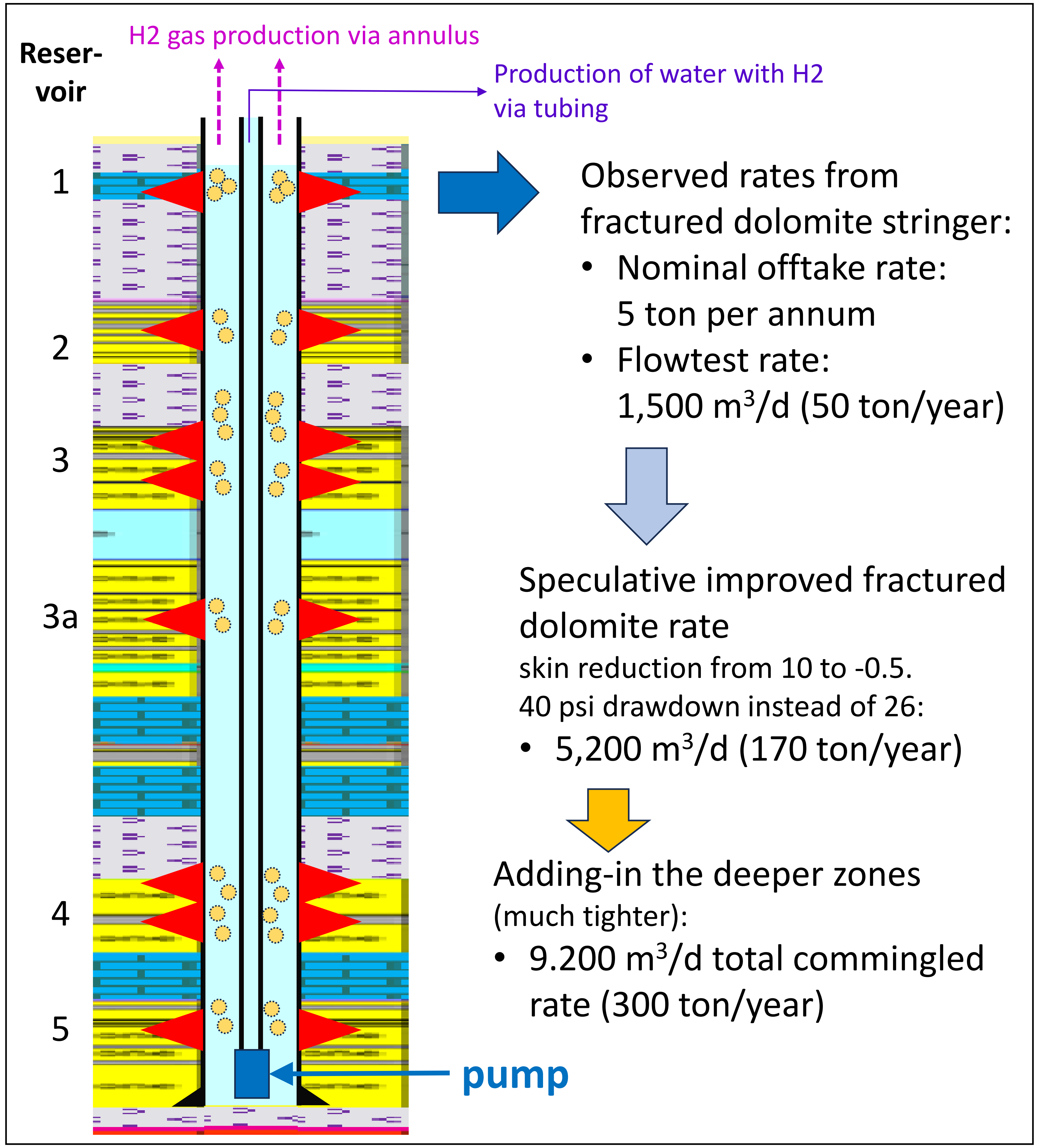
"Reservoir 1": H_2 test and production in Bougou-1

RF = 5%

Gas-shows

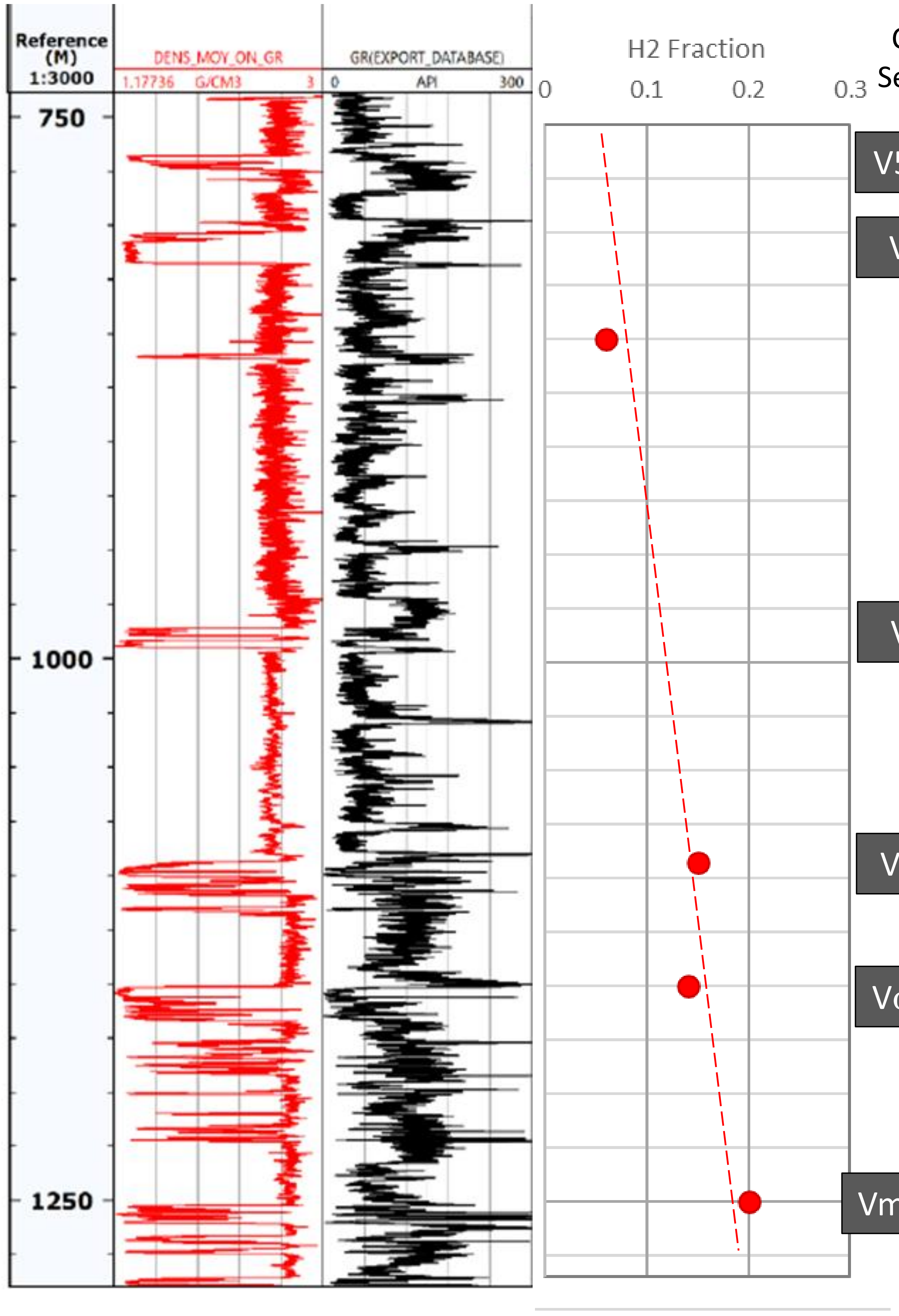
Strong ↔ Weak

Figure 5



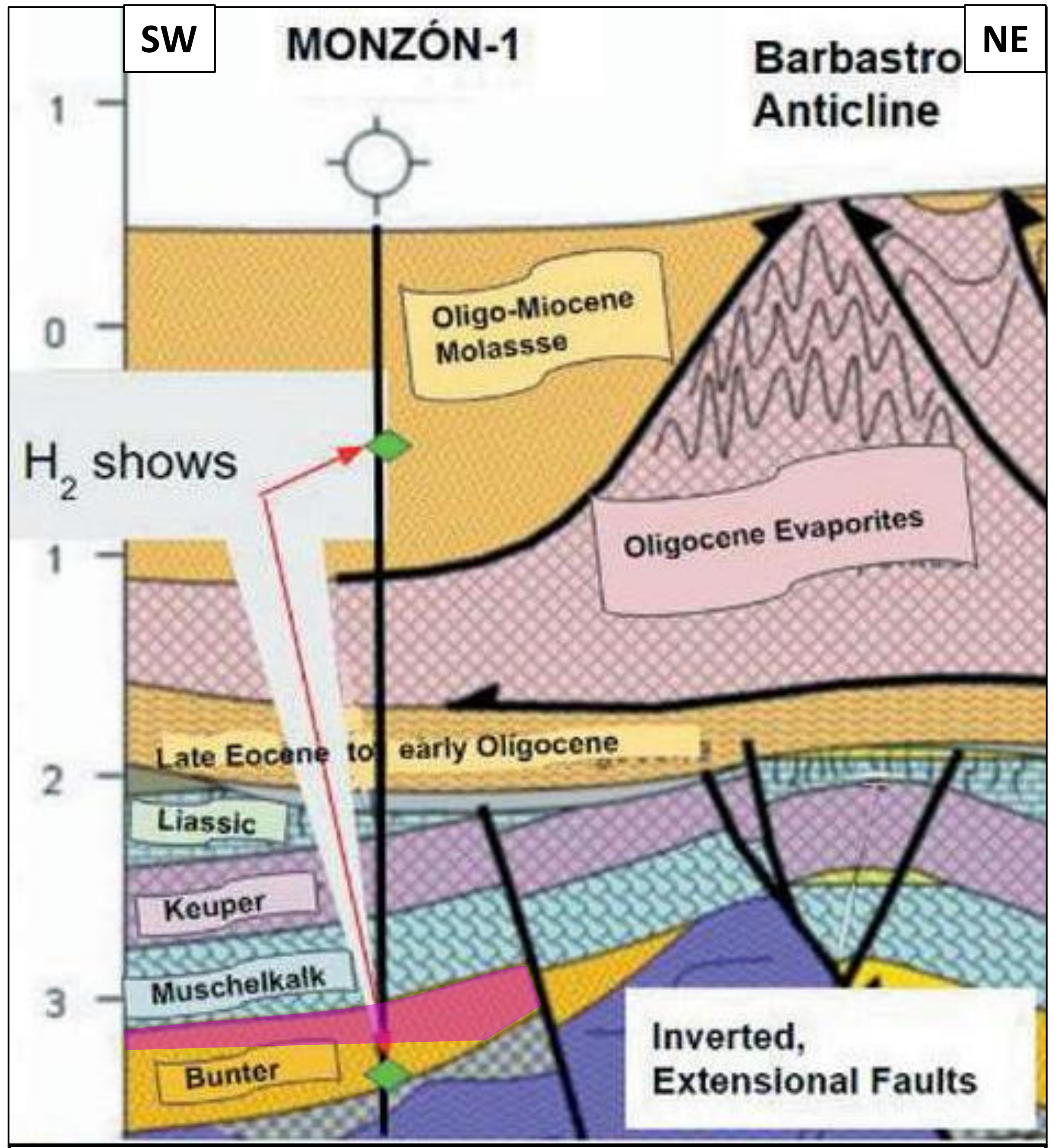
H2 gas production via annulus
Reser-
voir
Production of water with H2
via tubing
1
2
3
3a
4
5
Observed rates from
fractured dolomite stringer:
• Nominal offtake rate:
5 ton per annum
• Flowtest rate:
1,500 m^3/d (50 ton/year)
Speculative improved fractured
dolomite rate
skin reduction from 10 to -0.5.
40 psi drawdown instead of 26:
• 5,200 m^3/d (170 ton/year)
Adding-in the deeper zones
(much tighter):
• 9.200 m^3/d total commingled
rate (300 ton/year)
pump

Figure 6



Coal Seams	Net	Density	Gas Content	H_2 Content	Gross GIIP	H_2 in-place	
	m	g/cc	m³/t	frac	MMsm³/km²		*ton/km²*
V5-6-7	4.5	1.60	7.3	0.06	52	3	*286*
V8-9	13.5	1.40	9.6	0.07	181	13	*1,170*
Vi-i-i	6.9	1.55	9.2	0.13	99	13	*1,124*
Vz-z-y	12.2	1.60	10.1	0.15	197	30	*2,652*
Vα-β-γ	14.9	1.45	9.4	0.14	203	29	*2,559*
Vm-m-n	10.5	1.65	9.9	0.20	171	34	*3,078*
				TOTAL	**903**	**121**	***10,869***

Figure 7



Modified after Atkinson et al (2022)

Monzon PlayType-3 Success Outcome

(H_2 gas discovery of 98% purity in Bunter)

	Net	Porosity	Sw	Bgi	H2 in-place	*H2 recove-rable*
	m	Frac	Frac	rm3/sm3	ton/km2	
gasleg	30	0.095	0.364	0.004	37,000	*30,000*
waterleg	25		0.900		6,000	*5,000*
				TOTAL	**43,000**	***35,000***

Well Productivity Assumptions:

5 years plateau, 80% of UR on plateau, 1 well per km^2

⇒ 5,600 ton/year/well

(170 Msm^3/day or 6 MMscf/d)

Figure 8

Metrics	Large Industrial Offtake				Local Offtake Options			Basis
	Petro-leum Refinery	Steel Plant	Ammonia Plant		District heating project	H_2-vehicle fuelling station	H_2-jet fuelling hub	
Annual demand (ton/yr)	50,000	70,000	280,000		1,300	1,500	32,000	Typical "average" facility size (Fig.1)
Contractual Supply Commitment	7 years							Minimum for a long-term GSA
Producer-Well Count per Offtake Option								
Wellcount assuming Bougou-1 testrate	*1,000*	*1,400*	*5,600*		*26*	*30*	*640*	*50ton H_2/yr per well*
Well count assuming multi-zone wells	*170*	*230*	*930*		*4*	*5*	*107*	*300ton H_2/yr per well*
Development-Area Size and Water Production (per offtake option, assuming no significant H_2 recharge)								
Resource-Area to be developed (km^2)	2,300	3,300	13,100		50	60	1,240	40psi depletion, EUR 150ton H_2/km2
Cumulative Water production (MMstb)	790	1,130	4,500		17	21	426	Material Balance, 40psi depletion
Development-Area Size and Water Production (per offtake option, assuming recharge of 50 ton H_2/km^2/year)								
Resource-Area to be developed (km^2)	2,100	2,900	11,700		50	60	1,240	40psi depletion, EUR 150ton H_2/km2
Cumulative Water production (MMstb)	720	1,000	4,020		17	21	426	Material Balance, 40psi depletion

Table 1

Metrics	Large Industrial Offtake				Local Offtake Options			Basis
	Petro-leum Refinery	Steel Plant	Ammonia Plant		District heating project	H_2-vehicle fuelling station	H_2-jet fuelling hub	
Annual demand (ton/yr)	50,000	70,000	280,000		1,300	1,500	32,000	Typical "average" facility size (Fig.1)
Contractual Supply Commitment	7 years							Minimum for a long-term GSA
Producer-Well Count and Gross Gas Production per Offtake Option								
Wellcount assuming CBM-analogue rate	*1,330*	*1,860*	*7,450*		*35*	*40*	*850*	*8.6 Mm^3 gross gas/day/well, H_2 = 13%*
Cum. Gross Gas Production ($MMsm^3$)	*28,900*	*40,600*	*162,500*		*760*	*870*	*18,600*	*450MMsm3 gas UR/km^2, H_2 = 13%*
Development-Area Size and Water Production (per offtake option, assuming no significant H_2 recharge)								
Resource-Area to be developed (km^2)	64	90	360		1.7	1.9	41.3	EUR 5,430ton H_2/km^2
Cumulative Water production (MMstb)	22	30	121		0.6	0.6	13.9	depletion to 300psi P-abandonment
Development-Area Size and Water Production (per offtake option, assuming recharge of 50 ton H_2/km^2/year)								
Resource-Area to be developed (km^2)	62	87	350		1.6	1.9	40.0	EUR 5,430ton H_2/km^2
Cumulative Water production (MMstb)	21	29	118		0.5	0.6	13.4	depletion to 300psi P-abandonment

Table 2

Metrics	Large Industrial Offtake				Local Offtake Options			Basis
	Petro-leum Refinery	Steel Plant	Ammonia Plant		District heating project	H_2-vehicle fuelling station	H_2-jet fuelling hub	
Annual demand (ton/yr)	50,000	70,000	280,000		1,300	1,500	32,000	Typical "average" facility size (Fig.1)
Contractual Supply Commitment	7 years							Minimum for a long-term GSA
Producer-Well Count per Offtake Option								
Well count assuming vertical wells	*9*	*13*	*51*		*1*	*1*	*6*	*6MMscf/d (5,500 ton H_2/yr) per well*
Cum. Gross Gas Production (MMsm³)	*3,970*	*5,560*	*22,200*		*100*	*120*	*2,540*	*390MMsm3 gas UR/km², H_2 = 98%*
Development-Area Size and Water Production (per offtake option, assuming no significant H_2 recharge)								
Resource-Area to be developed (km²)	10	14	58		0.3	0.3	6.6	EUR 35,000 ton H_2/km², Pabd 850psi
Cumulative Water production (MMstb)	negligible							
Development-Area Size and Water Production (per offtake option, assuming recharge of 50 ton H_2/km²/year)								
Resource-Area to be developed (km²)	10	14	57		0.3	0.3	6.5	EUR 35,000 ton H_2/km², Pabd 850psi
Cumulative Water production (MMstb)	negligible							

Table 3

	Large free gascap, nearly-pure H_2 ***Reference Case***	Large free gascap, H_2 mixed with other gases	Small free gascap, nearly-pure H_2	Aqueous only, nearly-pure H_2
Subsurface Parameters and In-Place Resource				
Max. gas cap / avg. gas pay (m)	60 / 30	60 / 30	20 / 10	0
Hydrogen Fraction in gas	0.98	0.30	0.98	0.98
In-Place Gross Gas Resource Density ($MMsm^3/km^2$)	484	484	259	66
Resource Recovery				
Reservoir Pressure (psia) Initial / Final	5,450 / 850	5,450 / 850	5,390 / 4,390	5,360 / 5,260
Recoverable Gross Gas Resource Density ($MMsm^3/km^2$)	391	391	79	1.1
Recovery Factor	81%	81%	31%	2%
Recoverable Hydrogen Resource Density (ton/km^2)	34,000	11,000	7,000	100
Well Productivity				
Gross Gas Production per well (Msm^3/d)	171	171	35	3
H_2 production per well (ton/yr)	5,500	1,700	1,100	10
Water production ($MMstb/km^2$)	negligible	negligible	0.60	30.9

Table 4