Life Cycle Cost Assessment of an underground storage site

Dissemination level: PU – Public

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Revision History

Revision	Revision date	Summary of changes
0	21 January 2022	Initial version
1	29 April 2022	Revision based on early feedback and results, with focus on European context, and to include most likely assumptions in light of current knowledge

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1. Executive summary

As part of the Hystories project, funded by the EU under the Fuel Cells & Hydrogen Joint Undertaking Program (FCH-JU), WP7 – Ranking of geological sites will form a cornerstone between the technical / subsurface investigation work and the business / economic studies.

This Work Package includes a conceptual design of an underground storage site along with Life Cycle Cost Analysis (LCCA). The cost-estimate derived from this exercise will feed into WP5 – Modelling of the European energy system. Those costs estimates will also be one of the ranking criteria to build a prioritised list of prospects for hydrogen storage, along with technical criteria coming from WP1 to WP4 (WP1 – Geological assessment will, WP2 – Reservoir engineering and geochemistry, WP3 – Microbiology, WP4 – Material and corrosion). This detailed ranking of sites across Europe will then be used for a more detailed analysis of preselected sites within specific case studies in WP8 – European case studies.

In the absence of site-specific data (potential candidates have yet to be selected), the present document proposes a Life Cycle Cost Assessment of an underground storage of hydrogen in depleted fields, aquifers, and salt caverns, which means, a high-level estimation of the development (CAPEX), operation (OPEX), and abandonment (ABEX) costs of an underground storage site of hydrogen in depleted fields, aquifers, and salt caverns. This cost assessment is typically yielding figures within 30 to 50 % accuracy.

Main assumptions and parameters are those identified in deliverable D7.1 – Conceptual Design of an underground storage site, either based on a statistical review of existing analogues for natural gas storage or based on engineering judgment considering existing technical constraints.

The proposed cost model has been applied on the conceptual design cases defined in deliverable D7.1. From this application, the following rates are proposed for preliminary estimation and European scale economic modelling:

Table 1: Costing rates – Orders of magnitude (MID case basis of deliverable #7.1)

COST RATE	UNIT	SALT CAVERNS	POROUS MEDIA
SUBSURFACE CAPEX RATE per working gas capacity	EUR per KWh_H_2(LHV) *[Range]**	0.51 *[0.44 – 0.69]*	0.20 *[0.11 – 0.45]*
SURFACE CAPEX RATE per withdrawal flowrate max. capacity	EUR per KW_H_2(LHV)	205	645**
VARIABLE OPEX RATE per cycled quantity For COE = 60 EUR/MWh	EUR per MWh_H_2(LHV)	2.25	3.83
FIXED OPEX RATE*** % of related CAPEX / year	% Surface CAPEX / year	3.7%	3.7%
	% Subsurface CAPEX / year	0.4%	1.5%

* Subsurface CAPEX rate per storage volume capacity is highly dependent on the number of wells required to reach storage target performance.
** Surface CAPEX rate per withdrawal flowrate capacity is highly dependent on the purification unit requirements and on the installed compression power (ratio WTIR).
*** (Subsurface-related fixed OPEX to be cumulated to surface-related fixed OPEX

2. List of Acronyms and Units

ACRONYMS

AACEi	Association for the Advancement of Cost Engineering International
ABEX	Abandonment Expenditure
BOE	Basis of Estimate
BOP	Balance of Plant
CAPEX	Capital Expenditure
C_2H_6	Ethane
CH_4	Methane
CO_2	Carbon dioxide
CS	Carbon Steel
DN	Nominal Diameter
E&I	Electrical & Instrumentation
EMS	Engineering, Management & Services
EN	European Norm
EPC	Engineering, Construction & Procurement
FEED	Front End Engineering Design
FGF	First Gas Fill
GRP	Glass Reinforced Plastic
H_2	Hydrogen
H_2S	Hydrogen sulphide
HC	Hydrocarbon
HDPE	High density Polyethylene
ISBL	Inside battery limit
LCCA	Life Cycle Cost Assessment
LHV	Lower Heating Value
MCF	Material Cost Factor
minOP	Minimum Operating Pressure of the storage
MOP	Maximum Operating Pressure of the storage
NA	Not Applicable
NPS	Nominal Pipe Size
O&M	Operation & Maintenance

OPEX	Operational Expenditure
OSBL	Outside battery limit
PMC	Project Management Consultant: underground storage specialized third party services during cavern construction
PN	Nominal Pressure
PSA	Pressure Swing Adsorption
QHSE	Quality, Health, Safety and Environment
RFSU	Ready for Start-Up
SS	Stainless Steel
SU	Start-Up
TICBP	Total installed compression brake power
TSA	Temperature Swing Adsorption
WG	Working Gas
WH	Wellhead
WTIR	Withdrawal-to-injection capacity ratio (flowrates)

Units

or in.	inch
°C	degree Celsius
bar	1 bar = 10^5 Pa
bar/m	bar per metre
bara	bar absolute
barg	bar gauge
EUR	Euro
hr/d	hour per day
K	degree Kelvin
k€ or kEUR	1,000 Euro
kg	kilogram
km	kilometre
kW	kilowatt
m	metre
m^3	cubic metre
m^3/hr	cubic metre per hour

mm	millimetre
MW	megawatts
MWh	megawatt hour
Pa	Pascal
Sm^3	Standard cubic metre (at 15°C, 1.01325 bara)
Sm^3/d	Standard cubic metre per day
ton	1,000 kg
USD	US dollar

3. CAPEX model for subsurface facilities

3.1. Basis of Estimate (BOE)

3.1.1. Scope of CAPEX model for subsurface facilities

The CAPEX model presented in the sections below is based on the assumptions described in project deliverable D7.1. It covers the following elements:

- Development well drilling campaign i.e. operating / monitoring wells (all associated services, equipment and consumables).
- In the case of salt caverns, all the costs associated to the leaching phase i.e. leaching plant design, construction and operation as well as all the well services & equipment required during leaching.
- All gas completion elements (completion running services, completion equipment, accessories, etc.) including the surface equipment that is part of the well pressure envelope i.e. wellheads.

CAPEX model is based on an initial CAPEX only, without additional investment or development during storage life. Moreover, it has been assumed that the facility is built without site development phasing or gradual site capacity increase.

3.1.2. CAPEX exclusions

- For salt caverns only (leaching phase):
    - Fresh water production facilities and transport pipelines
    - Brine disposal facility: offshore pipeline and diffusor, or deep aquifer injection well
- For depleted fields:
    - Plugging and abandonment (P&A) activities of historical production and/or injection wells (if any) drilled as part of the production of the field.
- Both for salt caverns and depleted fields/aquifers:
    - Exploration & appraisal costs linked to seismic data acquisition, exploration / appraisal well drilling, fluid/core sampling analysis and associated studies.

With respect to the last bullet point, it should be noted that exploration & appraisal costs in the oil and gas industry tend to be excluded from the project economic assessments that are conducted as part of project final investment decision. They tend to be treated separately by oil and gas operators as research and development funds. For instance, exploration & appraisal work on a specific number of geological prospects entails that only a small portion of those prospects will eventually be developed as storage sites.

In addition, it can be easily understood that there is no simple correlation or straightforward approach to derive a cost estimate for exploration & appraisal activities. As every geological prospect is unique, and as a result of the intrinsic nature of subsurface uncertainty, one cannot estimate, for instance, the number of appraisal wells required to fully characterise a geological prospect, simply based on a few parameters describing the prospect (average insoluble content in salt formation, average depth, etc. for salt caverns and average porosity / permeability, average depth, etc. for porous media). Likewise, the number of appraisal wells required to establish the feasibility of hydrogen storage for a set of given specifications such as withdrawal gas rates, stored volume, pressure envelope, etc. is deeply related to the level of risk that the project owners are ready to accept for the project final investment decision.

Finally, the cost model presented in this document is not directly applicable to offshore environments as multiple scenarios may exist e.g. standalone offshore platform (floating or fixed installation), standalone subsea development without any platform, subsea tiebacks to existing offshore facilities, etc. Instead, a complexity factor may be introduced in D7.3 in order to consider and rank offshore prospects.

3.2. Costs related to salt caverns development (solution mining)

In accordance with Task 7.1 assumptions and in the absence of specific site information, the following typical values are assumed for the cavern geometrical basis of design and solution mining:

Table 2: Cavern geometrical features

Cavern geometry & salt features		
Cavern neck length	m	30
Last Cemented Casing Shoe Depth	m	1,000
Cavern height (low – mid – high)	m	311 – 155 – 85
Solution mining parameters		
Brine flowrate	m^3/hr	300
Leached Vol. per Work-over	m^3	100,000
First Gas Fill (FGF) parameters		
Outages during FGF	hr/d	2.0
Reduced capacity	%	15 %
Brine flowrate during FGF	m^3/h	250
Gas capacity parameters		
Max. Pres. Grad. @ Casing shoe	bar/m	0.18
Min. Pres. Grad. @ 2/3 cavern height depth	bar/m	0.06
Geothermal gradient	K/m	0.03
Standard Conditions P, T		
Standard Pressure	bara	1.01325
Standard temperature	degC	15.0

Complete set of parameters can be found in Task 7.1 report part 3.3.1.

Costs presented in the following chapters are valid only for above parameters values.

3.2.1. Development drilling and leaching completion costs

As part of salt cavern construction activities, it has been assumed that one well per cavern would be drilled. The architecture of the well is described in deliverable D7.1.

Development drilling and leaching costs covers the following costs:

Table 3: Development drilling and leaching completion main assumptions

Well equipment		Assumptions
	OCTG – permanent casing	Tubulars required for well construction: - 30" conductor pipe (50 m) - 20" surface casing (250 m) - 13 3/8" production casing (1000 m)
	Wellhead	Permanent wellhead for well lifespan
	OCTG – temporary leaching strings	Tubulars required per well for leaching completion: - 10 ¾" leaching string (1200 m) - 7" leaching string (1250 m)
	Leaching head	Temporary head for leaching operation only
Drilling & leaching completion operations		
	Civil works	Civil works including: - drilling platform (cement slab & gravel area) - cellar - installation of 30" conductor pipe - fencing - water collet - sceptic tank for bathroom & toilets
	Drilling rig mobilisation & demobilisation	Per mobilisation / demobilisation
	Drilling rig rate with all associated services Drilling operations are carried out 24/7	Daily rate includes rig & crew and all associated drilling services: - supervision - mudlogging - eventual MWD services - mud engineer and services - cement services - casing running services - wireline logs - wellhead services - drilling bit services - diesel consumption - forklift, crane & transport - guarding & house keeping
	Duration of drilling and leaching completion operations	42 days per well including 9 days contingencies
EMS – Engineering Management Services		
	Project Management Team / Engineering	Estimated 15% of total development drilling cost

The development drilling and leaching completion costs for salt caverns can be evaluated per following table:

Table 4 Development drilling and leaching main parameters and cost breakdown

Cost drivers	Cavern depth correlated	LCCS casing shoe Range [500 – 1500 m]
	Number of wellheads (assumed one WH / cavern)	Constrained by geology, see chapter 4.1.2 and task D7.1
	13 3/8" production casing material potentially in contact with H_2	Site specific, see chapter 4.1.3
	Drilling complexity index	Range [1 – 2] depending on local geology complexity
EPC COST	$\boldsymbol{EPC_4^{Salt}}$ [$\boldsymbol{k}$€]	$\boldsymbol{EPC_4^{Salt} = n_{WH}\left(1\,781 + 196 \cdot MCF_w + 86 \cdot \left(18 + 12 \cdot \frac{LCCS}{500}\right)\right) \cdot DCi}$ With $\boldsymbol{n_{WH}}$ = number of caverns (assumption one WH per cavern) $\boldsymbol{LCCS}$ = Last Cemented Casing Shoe in [m] – range [500 – 1500 m] $\boldsymbol{MCF_w}$ = Material Cost Factor for withdrawal stream, refer to relevant sections (4.1.3 & 4.2.1) $\boldsymbol{DCi}$ = Drilling Complexity index – range [1 – 2]

3.2.2. Leaching plant EPC costs

The leaching facilities enable injecting fresh water in the wells to dissolve the salt rock downhole, monitor and control the leaching process, and dispose (or possibly re-use) the brine by-product. These facilities are “temporary” equipment, in the sense that it is required only for salt cavern construction phase and can be dismantled afterward. Nevertheless, dismantlement cost of leaching plant and related equipment is assumed to be part of abandonment costs (ABEX), not CAPEX, as it is common to keep these facilities for future expansion of the site capacity.

Table 5: Leaching station main equipment and assumptions

Fresh water intake		**Assumptions**
	Fresh water intake Pumps	Horizontal centrifugal pumps 300m^3/hr each, 350 kW each 4 working + 1 stand-by
	Fresh water pond reserve	600 m^3
	Fresh water pipeline to leaching plant	16” PN20, CS 15 km
Leaching plant		
	Leaching pumps	Horizontal centrifugal pumps 300m^3/hr each,1200 kW each 4 working + 1 stand-by
	Pressure and flow control system, set of valves, sensors for ensuring leaching process safe control and monitoring	1 set
	Piping network from leaching plant to Well Heads	16” PN150, CS 500m/WH (same hypothesis as H2 operation)
	Piping network from WH to brine treatment	16” PN20, GRP 500m/WH (same hypothesis as H2 operation)
	Brine settlement pond	600 m^3
	Blanket fluid unit (nitrogen unit, see below)	1 Package
	Brine treatment unit including chemical injection systems	1 Package
	Diesel tank, and pumps	1 set
	Electrical substation including Emergency Diesel Generator. (Modular power supply substation)	1 module of 10MW power output, including 25% power margin.
	Leaching pumps housing	1 structural steel closed shelter
	FEED & PMC	Dedicated part for leaching definition and follow-up
Brine disposal system		
	Brine disposal pumps	Horizontal centrifugal pumps 300m^3/hr each, 350 kW each 4 working + 1 stand-by
	Brine disposal pipeline	16” PN20, CS 30 km

It is assumed that four caverns are leached in parallel at 300m^3/hr each. Injection and disposal flowrates are equal.

A nitrogen storage and vaporization unit is installed to provide gaseous nitrogen at a sufficient pressure to each well head. This unit is composed of a cryogenic storage of liquid nitrogen (20 bar, 40 m^3) supplied in bulk by truck, a reciprocating cryogenic pump to deliver the high pressure required, an atmospheric vaporiser, an electrical heater to ensure a positive temperature in the lines (in case of atmospheric vaporiser dysfunction or low ambient temperature), a metering and pressure control device and then a network (50 mm diameter) for the gaseous nitrogen to reach each blanketing connection at the well heads.

Depending on the brine disposal national regulation, a treatment of the leaching brine is to be designed, such as a settling pond and filtration unit.

Costs related to brine disposal are excluded from this model. The main options excluded for brine disposal would be:

- disposal to the sea
- injection in deep aquifer
- supply to salt production, chlorine or soda chemical industry

Cost related to the several options for freshwater sourcing (special intake facilities such as wells, seashore civil works, water treatment if required, etc.) facilities are excluded from this model. The main options excluded for freshwater supply would be:

- fresh water from a dam or a river
- fresh water from deep aquifer
- seawater intake
- fresh water from existing network

Other underground costs are excluded from the model:

- Wells: development wells, including all the wells services and drilling equipment, the casings, wellheads, tubing strings
- Cavern Leaching (see next chapter): including, O&M of leaching facilities, well services, tightness tests and cavern inspections
- Gas completion and First gas Filling (see next chapter): including cavern acceptance test, wellheads and completion equipment, debrining and snubbing equipment.

Table 6: EPC cost main parameters and cost breakdown for Leaching facilities

<table>
<tr><td rowspan="5">Cost drivers</td><td colspan="2">Total electrical pumping power</td><td colspan="2">Assumed ≤ 8 MW</td></tr>
<tr><td colspan="2">Cavern depth correlated with cavern Maximum Operating Pressure (MOP) and leaching pumps power requirements</td><td colspan="2">Set at -1000 m at casing shoe, leading to MOP = 180 barg</td></tr>
<tr><td colspan="2">Number of wellheads
(assumed one / cavern)</td><td colspan="2">Constrained by geology, see chapter 4.1.2 and Deliverable D7.1</td></tr>
<tr><td colspan="2">Fresh water pipeline length, material, and diameter</td><td colspan="2">Assumption: Carbon steel 16” PN20
Length used as a parameter of the model</td></tr>
<tr><td colspan="2">Brine disposal pipeline length; material, and diameter</td><td colspan="2">Assumption: Carbon steel 16” PN20
Material choice could be further optimized (HDPE, GRP etc.)
Length used as a parameter of the model</td></tr>
<tr><td>EPC COST</td><td>$\boldsymbol{EPC_1^{Salt}}$
$[\boldsymbol{k}€]$</td><td colspan="3">$$\boldsymbol{EPC_1^{Salt} = 50\,000 + 2\,350 \cdot n_{WH} + 640 \cdot (L_{FW} + L_{BD})}$$
With
$\boldsymbol{n_{WH}}$ = number of caverns
$\boldsymbol{L_{FW}}$ = Fresh water pipeline length in kilometres, ≤ 50 km (no intermediate pumping station)
$\boldsymbol{L_{BD}}$ = Brine disposal pipeline length in kilometres, ≤ 50 km (no intermediate pumping station)</td></tr>
<tr><td>EPC Cost breakdown</td><td colspan="2">Engineering
(EMS, FEED, PMC):
23%</td><td>Procurement:
31-38%</td><td>Construction:
40%-47%</td></tr>
</table>

3.2.3. Leaching operation and maintenance costs

Leaching operation and maintenance costs covers the following costs:

Table 7: Leaching operation and maintenance cost inclusions

Leaching plant O&M		Assumptions
	Manpower	17 persons, including operators by shift: - 1 x Leaching Plant Manager - 1 x Administrative - 1 x QHSE Manager - 4 x Control Room Operators on shift (Lead) - 6 x Wells and station Operators on shift - 1 x Maintenance manager - 1 x Mechanical Technician - 1 x E&I Technician - 1 x Leaching & workover manager
	Staff other costs	Vehicles, lunch & transport, tools, furniture, training, IT etc.)
	Maintenance	1% of CAPEX
	Operation (sub-contractors, technical assistance)	Fixed Cost / year
	Insurance & taxes	Excluded
Energy and fluids		
	Electricity	60 EUR / MWh
	Water	0.50 EUR / m^3
	Blanket fluid: Liquid bulk nitrogen supplied by truck, used for leaching & cavern acceptance test	130 EUR / ton
	Chemicals	Corrosion Inhibitor, coagulant, flocculant 4% on top of other costs
Brine & water analysis		
	Brine & water analysis	External lab
	Regulatory analysis	External lab
	Site lab consumables	Not applicable
Workovers		
	Rig & crew	all inclusive, mob-demob-crew-diesel, including crane/forklift and truck
	Rig standby	Per day
	Supervision	Per day
Wireline Logging services		
	Sonar	At each Work-over
	Interface	1 per month
	Casing pipe cuts	2 per cavern
Site monitoring		
	Pin survey	Per year
	Micro-seismic monitoring	Per year
Miscellaneous		
	Small crane & operator	for interfaces (wireline)
	Leaching residue disposal	Per ton
EMS		
	Project Management Team / Supervision / Engineering	20% of above costs

The leaching operation and maintenance costs can be evaluated per following table:

Table 8: Leaching operation and maintenance costs

Cost drivers	Number of working leaching pumps	Set to 4 working pumps, 300 m^3/hr each
	Cavern depth correlated with cavern Maximum Operating Pressure (MOP) and leaching pumps power requirements	Set at -1000 m at casing shoe, leading to MOP = 180 barg
	Number of wellheads (assumed one WH / cavern) & Free Gas Volume (per cavern)	Constrained by geology, see chapter 4.1.2 and task D7.1
EPC COST	$\boldsymbol{EPC_2^{Salt}}$ $[\boldsymbol{k}€]$	$\boldsymbol{EPC_2^{Salt}} =$ $\boldsymbol{d_{T.L}\,(28\,\cdot n_{WH} + 9\,500) + n_{WH}\left(87.5\cdot\left(\frac{COE}{60} + 1.4\right)\cdot\, d_{U.L} - 420\right)}$ With $\boldsymbol{n_{WH}}$ = number of caverns (assumption one WH per cavern) $\boldsymbol{d_{T,L}}$ = Total duration of leaching (all caverns) in [years] $\boldsymbol{d_{U,L}}$ = Duration of leaching for one cavern unit in [month] $\boldsymbol{COE}$ = cost of electricity = 60 EUR/MWh by assumption

Total duration of leaching of leaching, for all caverns, can be estimated by the following formulas:

$$\boldsymbol{d_{U,L}} = \left(\frac{1}{20}\,\boldsymbol{V_{cavern}} + \boldsymbol{8}\right)$$

$$\boldsymbol{d_{T,L}} = \frac{\boldsymbol{d_{U,L}}}{12}\cdot \boldsymbol{ROUND.UP}\left(\frac{\boldsymbol{n_{WH}}}{\boldsymbol{4}}\right)$$

$\boldsymbol{ROUND.UP}(\quad)$ function returns a number rounded up to next integer

For example: $ROUND.UP\left({}^{5}/_{4}\right) = ROUND.UP(1.25) = 2$

Valid for Four (4) working leaching pumps 300 m^3/hr each

With

$\boldsymbol{d_{U,L}}$	[months]	Duration of leaching for one cavern
$\boldsymbol{d_{T,L}}$	[years]	Total duration of leaching (all caverns)
$\boldsymbol{V_{cavern}}$	[thousands m^3]	Free Gas Volume per cavern
$\boldsymbol{n_{WH}}$	[-]	Number of caverns (assumption one WH per cavern)

3.2.4. Salt cavern conversion cost - Debrining & First Gas Fill

After final test of the salt caverns, conversion is the operation consisting of substituting leaching completion by gas completion string (and debrining string) emptying the cavern full of brine (debrining operation) by progressively injecting hydrogen in the storage.

Several options and parameters may impact the cavern conversion costs. Among them:

- Use of H_2 Gas Plant compressors or dedicated compressor rental
- Debrining flowrate between 50 m^3/hr and 250 m^3/hr
- Cavern depth

In this part, it is assumed that H_2 Gas Plant compressors are also used for first gas fill of the caverns.

Hydrogen molecule costs for first filling is excluded.

Salt cavern conversion, i.e. Gas completion and First gas Fill (FGF), covers the following costs:

Table 9: Debrining & conversion cost inclusions

Gas completion running		**Assumptions**
	Material	Per well: - Gas tubing, Debrining tubing - Packer& Acc., SSSV & Acc. - Xmas tree (gas), Debrining Tree - Control panel
	Services	Per well: - Workover rig (incl. Diesel) per day - Mobilisation / Demobilisation - Tubing running services - Tubing cleaning and inspection/preparation - Wellhead installation services - Slickline services - Logging services - Packer services - SSSV Services - Nitrogen and tests services - Welding engineering and services
	Miscellaneous	Per well: - Noise protection, Noise recording and check - Electrical installation - Phone - Water and brine furniture + waste treatment - Transportation and crane
Specific equipment		
	Debrining skid	1 unit on wellsite, includes: - Wellhead isolation ESD valve - Liquid / Gas separator for brine degassing - Degassed brine expedition pump - Decrystallisation unit - Vent system - Instrumentation and control system 2 caverns debrined in parallel

Gas (Hydrogen) plant O&M		
	Manpower	20 persons, including operators by shift - 1 x Gas Plant Manager - 1 x Administrative - 1 x QHSE Manager - 1 x Operation manager - 4 x Stations Operators on shift (Lead) - 6 x Stations Operators on shift (Deputy) - 1 x Maintenance Manager - 1 x Mechanical Engineer - 1 x Mechanical Technician - 1 x Control system, Elec. & Instrum. Engineer - 1 x E&I Technician - 1 x Warehouse Technician
	Staff other costs	Vehicles, lunch & transport, tools, furniture, training, IT etc.)
	Maintenance	1% of CAPEX
	Operation (sub-contractors, technical assistance)	Fixed Cost / year
	Insurance & taxes	Fixed Cost / year
Energy		
	Electricity	50 to 60 EUR / MWh
Other well operations		
	Logging during debrining	1 per cavern
	Cavern acceptance	1 per cavern
	Snubbing	1 per cavern
	Gas Sonar	1 per cavern
	Leaching plant O&M	Included in leaching costs
	Site monitoring	Included in leaching costs
EMS		
	Project Management Team / Supervision / Engineering	Percentage of above costs

Salt cavern conversion costs can be evaluated per following table:

Table 10: Salt cavern debrining and conversion costs

Cost drivers	Debrining flowrate, per cavern	50 to 250 m^3/hr
	Cavern depth correlated with cavern Maximum Operating Pressure (MOP) and leaching pumps power requirements	Set at -1000 m at casing shoe, leading to MOP = 180 barg
	Number of wellheads (assumed one WH / cavern) & Free Gas Volume (per cavern)	Constrained by geology, see chapter 4.1.2 and task D7.1
EPC COST	$\boldsymbol{EPC_3^{Salt}}$ $[\boldsymbol{k}€]$	$\boldsymbol{EPC_3^{Salt} = 6\,750 \cdot d_{T.C} + 1700 + n_{WH} \cdot \left(1.42 \cdot \frac{COE}{60} \cdot V_{cavern} + 2\,780\right)}$ With: $\boldsymbol{n_{WH}}$ = number of caverns (assumption one WH per cavern) $\boldsymbol{d_{T,C}}$ = Total duration of conversion (all caverns) in [years] $\boldsymbol{V_{cavern}}$ = Free Gas Volume per cavern in [thousands m^3] $\boldsymbol{COE}$ = cost of electricity = 60 EUR/MWh by assumption

Total duration of conversion phase, for all caverns, can be estimated by the following formulas:

$$\boldsymbol{d_{U,C}} = \left(\frac{1100}{24}\frac{\boldsymbol{V_{cavern}}}{\boldsymbol{Q_{debrining}}}\right)$$

$$\boldsymbol{d_{T,C} = \left(d_{U,C} \cdot ROUND.UP\left(\frac{n_{WH}}{2}\right) + 60\right)/365}$$

$\boldsymbol{ROUND.UP(\quad)}$ function returns a number rounded up to next integer

For example: $ROUND.UP\left({}^{5}/_{2}\right) = ROUND.UP(2.50) = 3$

Valid for two (2) caverns debrined in parallel

With

$\boldsymbol{d_{U,C}}$	[days]	Duration of debrining for one cavern
$\boldsymbol{d_{T,C}}$	[years]	Total duration of conversion (all caverns)
$\boldsymbol{n_{WH}}$	[-]	Number of caverns (assumption one WH per cavern)
$\boldsymbol{Q_{debrining}}$	[m^3/hr]	Debrining flowrate, per cavern (50 to 250 m^3/hr)
$\boldsymbol{V_{cavern}}$	[thousands m^3]	Free Gas Volume per cavern

3.3. Costs related to porous media

3.3.1. Porous media - Development drilling

For both aquifers and depleted fields, two types of wells are required:

- production wells: used for gas injection and withdrawal purposes.
- observation wells: in reservoir or caprock horizons such as upper aquifers, used for storage monitoring.

The production well architecture for production well is described in deliverable D7.1 :

- 20” conductor pipe at 50 m
- 13 3/8” surface casing at 250 m
- 9 5/8” production casing at 1200 m - LCCS
- 7” production tubing

The observation well architecture has been assumed for a monitoring well into the reservoir:

- 13 3/8” conductor pipe at 50 m
- 9 5/8” surface casing at 250 m
- 7” production casing at 1200 m - LCCS
- 5” tubing

All wells, production and observation ones, are assumed to be vertical.

Development drilling covers the following costs:

Table 11: Development drilling cost inclusions

Well equipment		Assumptions
	OCTG – permanent casing	Tubulars for production wells: - 20” conductor pipe (50 m) - 13 3/8” surface casing (250 m) - 9 5/8” production casing (1200 m) Tubulars for observation wells: - 13 3/8” conductor pipe (50 m) - 9 5/8” surface casing (250 m) - 7” production casing (1200 m)
	Wellhead	Permanent wellhead for well lifespan
	Christmas tree	XMT type 7 1/16” 3K for production well & type 4 1/16” 3K for observation well
	OCTG – permanent gas completion	Tubing for production wells: - 7” tubing (1200 m) Tubing for observation wells: - 5” tubing (1200 m)
	Gas completion equipment for both lower & upper completion	- Downhole safety valve - production packer - lower completion packer (type GP packer) - safety shear joint - sand control screens - swell packer - landing nipples & associated mechanical plugs
Drilling & completion operations		
	Civil works	Civil works including: - drilling platform (cement slab & gravel area) - cellar - installation of 30”/20” conductor pipe - fencing - water collet - sceptic tank for bathroom & toilets
	Drilling rig mobilisation & demobilisation	Per mobilisation / demobilisation Specific to production and observation wells
	Drilling rig rate with all associated services Drilling operations are carried out 24/7	Daily rate, specific to production and observation wells. Drilling rate includes rig & crew and all associated drilling services: - supervision - mudlogging - eventual MWD services - mud engineer and services - cement services - casing running services - wireline logs - wellhead services - drilling bit services - diesel consumption - forklift, crane & transport - guarding & house keeping
	Duration of drilling and leaching completion operations	43 days per well including 10 days contingencies for production well with LCCS at 1200 m 33 days per well including 5 days contingencies for observation well with LCCS at 1200 m
EMS – Engineering Management Services		
	Project Management Team / Engineering	Estimated 15% of total development drilling cost

The development drilling costs for porous media can be evaluated per following table:

Table 12 Development drilling cost breakdown and main parameters

Cost drivers	Cavern depth correlated	LCCS casing shoe Range [600 – 2000 m]
	Number of development wells Number of observation wells	Constrained by geology, see chapter 4.1.2 and task D7.1
	9 5/8” production casing & 7” completion material in contact with H_2	Site specific, see chapter 4.1.3
	Drilling complexity index	Range [1 – 2] depending on local geology complexity
EPC COST	$\boldsymbol{EPC_4^{Porous}}$ $[k€]$	$$EPC_4^{Porous} = \begin{cases} n_{WHprod}\cdot\left(1\,018\ + 960\cdot MCF_w + 86\cdot\left(19 + 12\cdot\frac{LCCS}{600}\right)\right)\cdot DCi \\ + \\ n_{WHobs}\cdot\left(628 + 618\cdot MCF_w + 46\cdot\left(21 + 6\cdot\frac{LCCS}{600}\right)\right)\cdot DCi \end{cases}$$ With n_{WHprod} = number of development wells n_{WHobs} = number of observation wells MCF_w = Material Cost Factor for withdrawal stream, refer to relevant sections (4.1.3 & 4.2.1) $LCCS$ = Last Cemented Casing Shoe in [m] – range [600 – 2000 m] DCi = Drilling complexity index – range [1 – 2]

3.3.2. First gas fill (FGF) of porous media

First gas fill phase consists of progressively injecting hydrogen in the storage.

Several options and parameters may impact the cavern first gas fill costs. Among them:

- Use of H_2 Gas Plant compressors or dedicated compressor rental
- Storage depth

In this part, it is assumed that H_2 Gas Plant compressors are also used for first gas fill of the storage.

Hydrogen molecule costs for first filling is excluded.

First gas filling, covers the following costs, which are in first approach the same for both aquifers and depleted fields:

Table 13: Aquifers FGF cost inclusions

Gas (Hydrogen) plant O&M		
	Manpower	20 persons, including operators by shift - 1 x Gas Plant Manager - 1 x Administrative - 1 x QHSE Manager - 1 x Operation manager - 4 x Stations Operators on shift (Lead) - 6 x Stations Operators on shift (Deputy) - 1 x Maintenance Manager - 1 x Mechanical Engineer - 1 x Mechanical Technician - 1 x Control system, Elec. & Instrum. Engineer - 1 x E&I Technician - 1 x Warehouse Technician
	Staff other costs	Vehicles, lunch & transport, tools, furniture, training, IT etc.)
	Maintenance	1% of CAPEX for Process facilities & BOP related to compression stream
	Operation (sub-contractors, technical assistance)	1% of CAPEX for Process facilities & BOP related to compression stream
	Insurance & taxes	2% of CAPEX for Process facilities & BOP related to compression stream
Energy		
	Electricity	60 EUR / MWh
EMS		
	Project Management Team / Supervision / Engineering	Percentage of above costs

Aquifer FGF costs can be evaluated per following table:

Table 14: Aquifers FGF costs

Cost drivers	Total gas volume (working gas and cushion gas)	Site specific
	Withdrawal-to-Injection Capacity Ratio (WTIR)	See chapter 4.1.2
EPC COST	$\boldsymbol{EPC_3^{Salt}}$ [$\boldsymbol{k}$€]	$$\boldsymbol{EPC_3^{Porous} = 2\,400 \cdot d_{FGF} + 2\,100 \cdot \frac{COE}{60}}$$ With $\boldsymbol{d_{FGF}}$ = Total duration of First Gas Fill in [years] $\boldsymbol{COE}$ = cost of electricity = 60 EUR/MWh by assumption

Total duration of FGF phase can be estimated by the following formulas:

$$d_{FGF} = \left(60 + \cdot\, 1.10 \cdot \frac{WTIR \cdot (V_{WG} + V_{CG})}{Q_w}\right)/365$$

With

$\boldsymbol{d_{FGF}}$	[years]	Total duration of First Gas Fill
$\boldsymbol{V_{WG}}$	[million Sm^3]	Working gas volume
$\boldsymbol{V_{CG}}$	[million Sm^3]	Cushion gas volume
$\boldsymbol{Q_w}$	[million Sm^3/d]	Total storage maximum withdrawal flowrate in [million Sm^3/day]
$\boldsymbol{WTIR}$	[-]	Overall withdrawal-to-Injection capacity ratio of the storage

3.4. Cushion gas

The estimated cost associated to the volume of hydrogen cushion gas to be injected can be expressed as follows:

Table 15: Cushion gas cost estimation

CG $[k€]$	$$CG = \frac{x_{CG}}{(1 - x_{CG})} \cdot H_2Cost \cdot V_{WG} \cdot 85_{[ton_{H2}/million\ Sm^3]}$$ With x_{CG} = Cushion Gas to Total Gas ratio according deliverable 7.1 V_{WG} = Working Gas Volume [million Sm^3] $H_2Cost = 2.00\ EUR/kg$

3.4.1. Salt caverns

In a salt cavern, as presented in Hystories Deliverable D7.1, Cushion Gas is required to maintain the cavern above or at a minimum pressure, to ensure the cavern integrity. This Cushion Gas cannot be withdrawn until the decommissioning of the cavern, and may only then be sold, and e.g. support decommissioning cost should it still have an economic value. It has to be invested during the First Gas Fill of the cavern and can be considered as a « fixed asset » for the entire duration of the cavern design life. As no cavern can store gas without this initial investment, it will be added to the CAPEX to ensure comparability with other storage techniques.

3.4.2. Depleted fields and aquifers

In aquifer storage, part of the injected gas cannot be withdrawn and will remain trapped in the reservoir during operations, and even when decommissioning the storage. This gas is also called Cushion Gas. It is a required investment during the first fill of the storage. Deliverable D7.1 recommends using the value of 50% of the total gas (Table 11).

In depleted fields, the role of the cushion gas is played by native gas of the reservoir. For hydrogen storage, however, it may be necessary to inject hydrogen as a cushion gas in order limit hydrogen blending with native gas. A detailed and site-specific analysis would be required to determine the cushion gas for depleted field.

It is considered in the following that the same value can be taken for depleted fields and aquifers, 50%, knowing that it is a higher bound for depleted fields.

3.5. Contingencies for subsurface facilities

For this cost model, contingencies will be fixed at 20% of the following EPC costs and cushion gas costs ($\boldsymbol{CG}$):

- Salt caverns
  - Development drilling and leaching completion costs ($\boldsymbol{EPC_4^{Salt}}$)
  - Leaching plant EPC costs ($\boldsymbol{EPC_1^{Salt}}$)
  - Leaching operation and maintenance costs ($\boldsymbol{EPC_2^{Salt}}$)
  - Salt cavern conversion cost – Debrining & First Gas Fill ($\boldsymbol{EPC_3^{Salt}}$)
- Porous media
  - Development drilling ($\boldsymbol{EPC_4^{Porous}}$)
  - First gas fill (FGF) of porous media ($\boldsymbol{EPC_3^{Porous}}$)

Table 16: Contingencies related to subsurface

$\boldsymbol{CONT_{Subsurface}^{Salt/Porous}}$ $[\boldsymbol{k€}]$	$\boldsymbol{CONT_{Subsurface}^{Salt} = 20\% \cdot (EPC_1^{Salt} + EPC_2^{Salt} + EPC_3^{Salt} + EPC_4^{Salt} + CG)}$ $\boldsymbol{CONT_{Subsurface}^{Porous} = 20\% \cdot (EPC_3^{Porous} + EPC_4^{Porous} + CG)}$

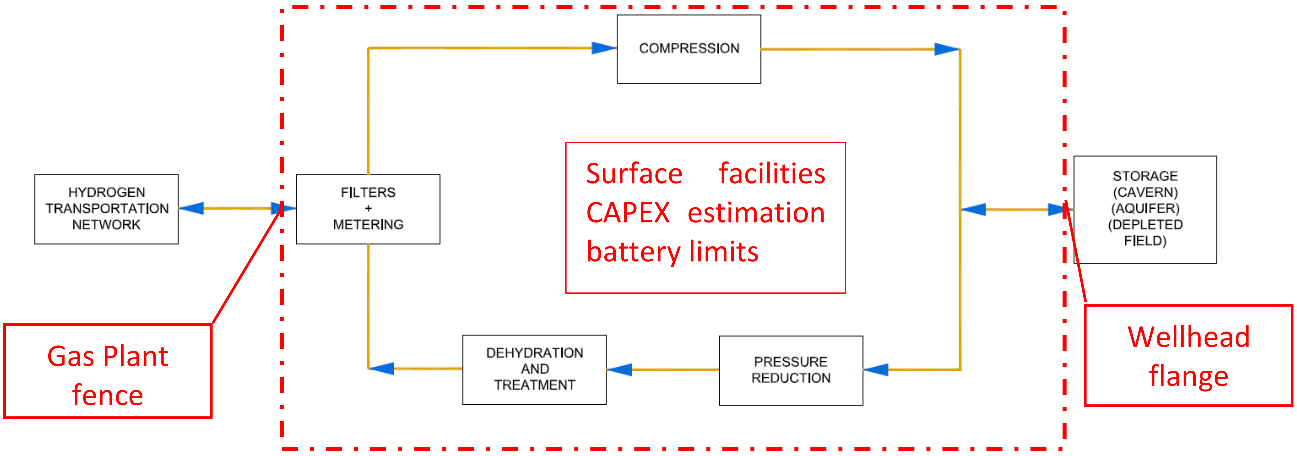
4. CAPEX model for surface facilities

4.1. Basis of Estimate (BOE)

4.1.1. Scope of CAPEX model for surface facilities

The following CAPEX model is based on same assumptions as Hystories deliverable D7.1. Below are summarized the battery limits of scope of present CAPEX model for surface facilities:

Figure 1: Battery limits of CAPEX model for surface facilities



CAPEX for surface facilities are evaluated for typical facilities from connection point at plant fence, up to flange at wellhead as shown on above Figure 1.

This block flow diagram illustrates the typical case, where the storage pressure is higher than that of the transportation network. The rare case where, for underground storages at shallow depth, compression would be required for gas withdrawal is excluded.

CAPEX model is based on an initial CAPEX only, without additional investment or development during storage life. Moreover, it has been assumed that the facility is built without site development phasing or gradual site capacity increase.

4.1.2. Model parameter ranges

Design parameters concerning Hydrogen streams, such as the maximum achievable flowrates, whether in injection of in withdrawal phase, or the storage pressure operating range are usually constrained by local geology and shall be evaluated and assessed during the early stage of the Project by a specialized company.

The proposed cost model, is deemed representative within the following main design parameters envelop:

Table 17: Main design parameters range

DESIGN PARAMETER	RANGE	REMARK
Minimum storage operating pressure (minOP)	60 barg – 70 barg	Geology dependent
Maximum storage operating pressure (MOP)	100 to 240 barg	Geology dependent
H_2 stream minimum operating pressure at compression inlet	From 30 barg, 30 °C To 60 barg, 30 °C	Electrolysis input dependent or Transportation network pressure dependent
Maximum total design withdrawal flowrate	0 to 30 million Sm^3/d (0 to 2500 tons_H2/d)	Geology dependent
Withdrawal-to-Injection Capacity Ratio (WTIR)	1 to 5 (usually around 2)	Techno-economical choice
Total installed compression brake power (TICBP)	1 to 80 MW	Techno-economical choice

Reference to the design cases described in Hystories deliverable D7.1 – Conceptual Design of an underground storage site, will be highlighted in the following chapters. For memory:

Table 18: Conceptual Design cases (deliverable 7.1)

DESIGN PARAMETER		Unit	Salt caverns storage			Porous media		
			LOW	MID	HIGH	LOW	MID	HIGH
Development wells count	n_{WH} or n_{WHprod}	[-]	4	8	16	5	24	71
Observation wells count	n_{WHobs}	[-]	NA			1	6	34
Free gas volume per cavern	V_{cavern}	X 1000 m_3	815	380	185	NA		
Working Gas Volume per cavern	-	[million Sm^3] Per cavern	62.5	31.25	15.625			
Cushion Gas to Total Gas ratio	x_{CG}	[-]	47%	43%	41%	50%		
Total Working Gas volume (for the site)	V_{WG}	[million Sm^3]	250			550		
Last Cemented Casing Shoe depth	$LCCS$	[m]	1 000			1 200		
Maximum storage operating pressure	MOP	[barg]	180			130		
Minimum storage operating pressure	$minOP$	[barg]	70			60		
Maximum withdrawal flowrate per cavern	-	[million Sm^3/d]	5.91	2.79	1.36	NA		
Maximum total design withdrawal flowrate (for the site)	Q_w	[million Sm^3/d]	23.6	22.3	21.8	8.25		

4.1.3. Material selection

Material fit for hydrogen purpose is part of the WP4 – Material and corrosion.

Material choice for process parts in contact with hydrogen is site dependent, as it may vary with the operating conditions and the potential contaminants, especially on the storage withdrawal stream for depleted fields or aquifer underground storages, from the wellheads till the potential hydrogen purification units (refer to dedicated chapter 4.2.4).

As the purpose of this cost model is not to freeze design choices, the material cost factors (MCF) are set as an input parameter of the cost model.

Relative Costs of Materials of Construction range typically within the values in following table:

Table 19: Relative Costs of Materials of Construction

Material	Material Cost factor (MCF) (weight basis)
Carbon Steel (raw material)	1
Stainless Steel 316L (raw material)	3.5 – 4.5

4.1.4. Surface facilities CAPEX breakdown and assumptions

The following chapters are describing the main CAPEX breakdown with main cost driving parameters. At this conceptual / feasibility study stage, the Surface Facilities CAPEX estimation is based on factorization on equipment and parametric model, with in-house data.

The result will be a Class 4 cost estimate as per Association for the Advancement of Cost Engineering International (AACEi) Classification, leading to a +/- 30% to 50% accuracy.

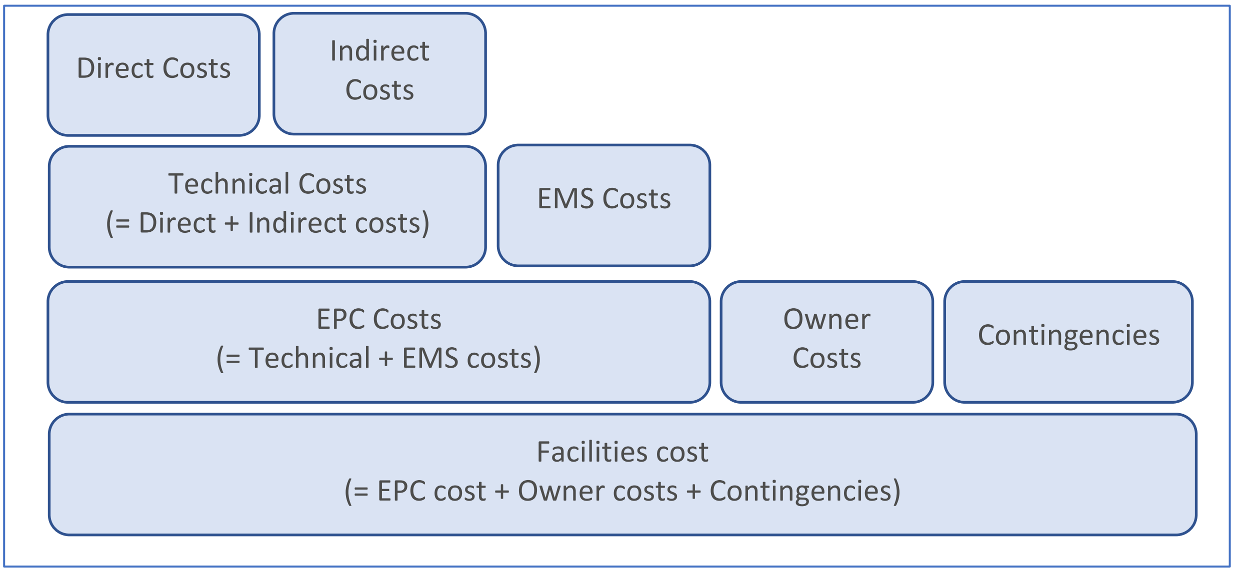
The (CAPEX) capital cost for the Engineering, Procurement and Construction (EPC) comprises of all the expenditures associated with the primary creation of the specific plant or facility: this usually embraces the following described direct and indirect construction and engineering related elements.

Costs given in following chapters will be in Euro, 2020 base, for a typical project located in France. A location factor, depending on the country the specific project is located, may be introduced in D7.3 in order to consider and rank specific sites.

No fluctuation of raw materials costs during construction duration is assumed. The purpose of this CAPEX model is to provide a tool for analysing various case studies / business economic models.

Exchange rate at end of year 2020: 1.00 EUR = 1.2271 USD (Source European Central Bank, Eurostat extract January 5th, 2021).

Figure 2: Surface facilities CAPEX breakdown structure



Technical costs (Direct costs + Indirect Costs) are evaluated with the following philosophy:

- Process blocks (system or unit) identification and main components (process equipment) characteristics definition.
- Main equipment Ex-Works cost estimation by scaling factors (Chilton's factors or equivalent).
- Main equipment related Direct + Indirect costs estimation by Lang's factors or equivalent: it will cover related bulk material procurement, associated construction costs, allowances, general permanent facilities and infrastructure, interconnections, spare parts (capital spare parts, commissioning spare parts), transportation, logistical support, construction temporary facilities.

Engineering Management Services (EMS) are evaluated as a percentage of Technical Costs in addition to it. They cover:

- Detailed Engineering,
- Procurement, purchasing, sub-contracting,
- Contractor management,
- Site supervision,
- Assistance to plant commissioning and start-up.

Owner (Company) costs are excluded from the present model, except for Basic Engineering / FEED (Front End Engineering Design) and PMC (Project Management Consultant: underground storage specialized third party services during cavern construction). They are listed in the Cost Exclusion list in dedicated chapter.

Contingencies are usually evaluated at about 20 to 25% of the above costs and are added on top of the estimate to complete the facilities cost (Technical costs + EMS + Owner costs) instead of being allocated to the sections previously defined. Contingencies cater for uncertainties in the estimate which are likely to occur, but which cannot be specifically identified at the time the estimate is prepared. Contingencies caters for:

- Errors of the estimation model,
- Uncertainties on unit costs,
- Uncertainties on quantities,
- Possible variations of the workforce,
- Variations of productivity,
- Risks associated to the selected process,
- Minor changes of design.

Contingency provisions DO NOT cater for exclusions of the estimate.

4.1.5. CAPEX Exclusions

The following costs are excluded from the CAPEX model:

- Owner (Company) costs:
    - Surveys
    - Project management
    - Insurances
    - Certification and expertise
    - Ready for start-up activities
    - Land acquisition, right of way
    - Taxes, customs duties, harbour fees
- Hydrogen supply and production facilities (electrolysis unit, H_2 pipelines, Tank Truck Loading Gantry if any, etc.).
- Two-year spare parts (included in OPEX). However, commissioning & start-up spare parts, Ready for Start-Up (RFSU) and Start-Up (SU) costs are included in the estimate.
- Pre-operation costs (training of operators, first fill of chemical products, etc.
- Cushion gas,
- Operation costs (OPEX) covered in subsequent sections,
- Abandonment costs (ABEX) covered in subsequent sections,
- Escalation (inflation), exchange rate variations and currency variations,
- Raw materials price fluctuations,
- Finance fees,

- General expenses of local operating subsidiaries,
- Risks covered by insurances,
- Management Reserve: amount added to an estimate to allow for discretionary management purposes outside of the defined scope of the project, as otherwise estimated,
- Change in scope or in Basis of design, process design modifications, major market effects, lack of competition, major risks, Force Majeure cases.
- Subsurface costs developed in dedicated chapter, site investigation, drilling expenditure, wells, well completions and wellhead equipment,
- Design, construction, and operation of leaching facilities and debrining phase costs as they are considered and included in subsurface costs.

Finally, the cost model presented in this document is not directly applicable to offshore environments as multiple scenarios may exist e.g. standalone offshore platform (floating or fixed installation), standalone subsea development without any platform, subsea tiebacks to existing offshore facilities, etc. Instead, a complexity factor may be introduced in D7.3 in order to consider and rank offshore prospects.

4.2. Technical costs elements for different units

4.2.1. Hydrogen process plant

EPC cost described here below are applicable for the three storage technologies: salt caverns, aquifers and depleted fields. These costs are highly dependent on the specificities of the site.

Following cost estimation figures are based on process sparing philosophy of 2 x 50%.

COMPRESSION STREAM:

The compressors selected are reciprocating compressors, driven by electric motors.

For High Pressure case, each compression train is split into two compression stages, for a total of 4 machines. For Low Pressure case, only 2 machines are assumed.

Following figures are including technical costs and EMS costs for the compressor itself, its auxiliaries, ancillaries, and appurtenances. Each compression unit is considered as a package equipment. Each unit includes:

- One Electric motor,
- One suction scrubber,
- Air coolers at compression outlet,
- Compressor outlet de-oiler to remove most of the oil vapor,
- Lubrication system, compressor utilities.

The following related cost items are aggregated with compression EPC costs:

- Compressor housing,
- Electrical substation (dimensioned for underground storage operation).
- ISBL (inside battery limit) piping networks:
  - Compression upstream piping: 500 metres, diameter sized for compression design flowrate and minimum suction pressure (30 barg), thickness sized for on maximum suction pressure (60 barg).
  - Compression downstream piping: 500 metres, diameter sized for compression design flowrate and minimum discharge pressure (60 barg), thickness sized for maximum discharge pressure (100 to 240 barg).
- Owner costs including FEED (Front End Engineering Design) and PMC (Project Management Consultant: underground storage specialised third party services during cavern construction).

It is assumed modular power supply substation, each module of 10MW. In first simplified approach, total electrical power demand is assumed to be equal to:

- Compression units electrical demand: considering process calculated brake power, with 85% efficiency for electrical drives, plus 20% electrical power rating margin
- Other consumers and Electrical Substation margin: additional 1 250 kW / (million Sm^3/d).

The costs associated to filtering units and metering units are adapted following the design pressure case.

WITHDRAWAL STREAM:

Withdrawal stream includes the following:

- Fiscal metering. It is assumed that the same metering is used for H_2 import in the storage and for H_2 export from the storage,
- Filtering units (common for compression and metering units,)
- Drying units: molecular sieves @ about 80 barg,
- Pressure reduction systems,

- ISBL (inside battery limit) piping networks:
  - From WH up to and including pressure reduction system: 300 metres, diameter sized for maximum storage withdrawal flowrate and minimum storage operating pressure (60 barg), thickness sized for maximum discharge pressure (100 to 240 barg).
  - From expansion system up to and including dehydration units and downstream pressure reduction system: 200 metres, diameter and wall thickness sized for maximum storage withdrawal flowrate and dehydration unit design pressure.
  - From second pressure reduction system up to battery limit (transport network): 300 metres, diameter and wall thickness sized for maximum storage withdrawal flowrate and transport network operating pressure (30 to 60 barg).
- Owner costs including FEED (Front End Engineering Design) and PMC (Project Management Consultant: underground storage specialised third party services during cavern construction).

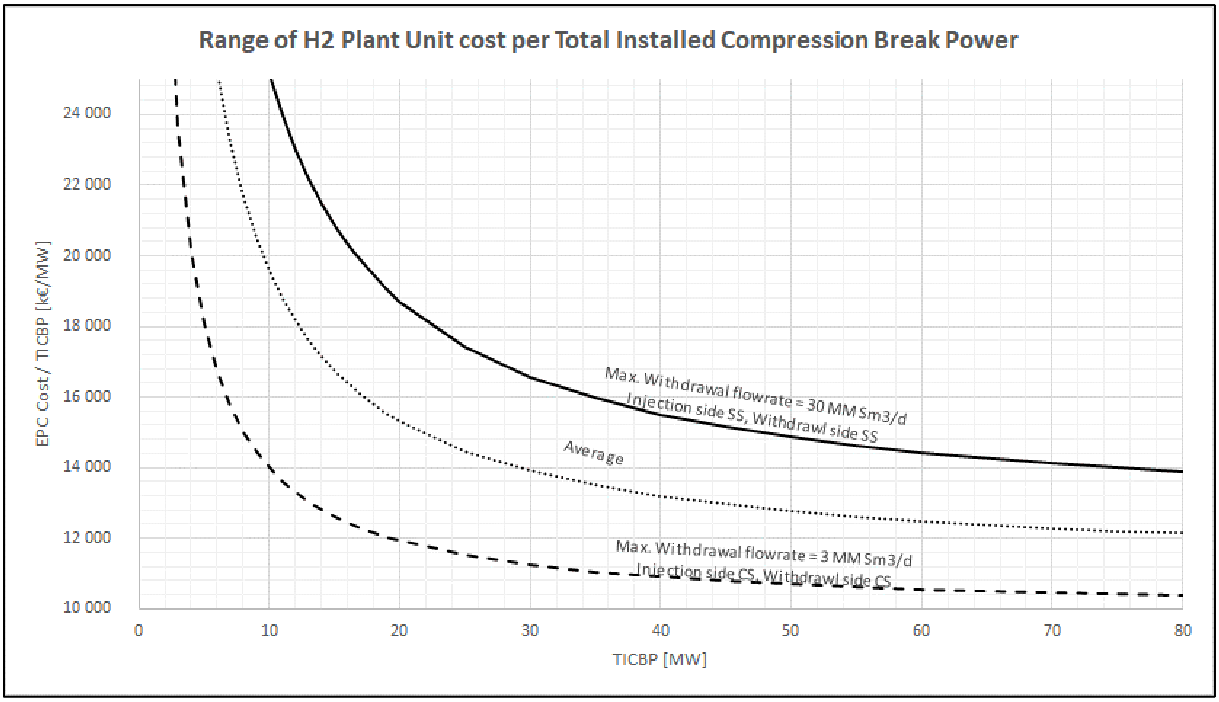
Main parameters and EPC cost figures are summarized in the tables below:

Table 20: EPC cost main parameters and breakdown for filtering, drying & compression, and metering units

<table>
<tr><td rowspan="6">Cost drivers</td><td colspan="2">Material of construction for process parts in contact with H_2</td><td colspan="2">Site specific, see chapter 4.1.3</td></tr>
<tr><td colspan="2">Total compression brake power</td><td colspan="2">See chapter 4.1.2
and below formula</td></tr>
<tr><td colspan="2">Total maximum withdrawal flowrate</td><td colspan="2">Site specific, see chapter 4.1.2</td></tr>
<tr><td colspan="2">Withdrawal-to-Injection Capacity Ratio (WTIR)</td><td colspan="2">See chapter 4.1.2</td></tr>
<tr><td colspan="2">Maximum storage operating pressure</td><td colspan="2">Site specific, see chapter 4.1.2</td></tr>
<tr><td colspan="2">Minimum compression suction pressure</td><td colspan="2">See chapter 4.1.2</td></tr>
<tr><td>EPC COST</td><td>$\boldsymbol{EPC_1}$ $[\boldsymbol{k€}]$</td><td colspan="3">$$\boldsymbol{EPC_1} = \begin{cases} \mathbf{8\,655 \cdot (1 + \boldsymbol{MCF_i} \cdot 14\%) \cdot \boldsymbol{TICBP} + 20\,700} \\ \mathbf{+\, 9\,100 \cdot (1 + \boldsymbol{MCF_w} \cdot 11\%) \cdot \boldsymbol{Q_w}^{0.643}} \end{cases}$$
With
$\boldsymbol{MCF_i}$ = Material Cost Factor for injection (compression) stream
$\boldsymbol{MCF_w}$ = Material Cost Factor for withdrawal stream
$\boldsymbol{TICBP}$ = Total Installed Compression Brake Power in [MW]
$\boldsymbol{Q_w}$ = Total storage maximum withdrawal flowrate in [million Sm^3/day]</td></tr>
<tr><td>EPC Cost breakdown</td><td colspan="2">Engineering (EMS):
14-19%</td><td>Procurement:
35-51%</td><td>Construction:
25-39% | FEED & PMC
9%</td></tr>
</table>

The following figure shows the unit cost envelop for process facilities per compression installed brake power.

Figure 3: Range of H2 Plant Unit cost per Total Installed Compression Break Power



The total installed compression brake power can be estimated by the following formulas:

$$\boldsymbol{TICBP = 4.545 \cdot n \cdot Q_i \cdot \left(\tau^{\frac{0.350}{n}} - 1\right)}$$

Overall compression ratio:

$$\tau = \frac{MOP + 1}{netOP + 1}$$

$$Q_i = \frac{Q_w}{WTIR}$$

Above correlation are valid only for the purpose of this estimation and related assumptions.

Valid for:

$$Q_{withdrawal}[\text{millions Sm}^3/\text{day}] \in [3 - 30]$$

$$WTIR \in [1 - 5]$$

H_2 Suction temperature 1st stage = 30 °C

H_2 Suction temperature 2nd stage = 40°C

For each stage, Discharge temperature ≤ 135°C, i.e.

$$\tau \leq 2.34 \Rightarrow n = 1$$

$$2.34 < \tau \leq 4.54 \Rightarrow n = 2$$

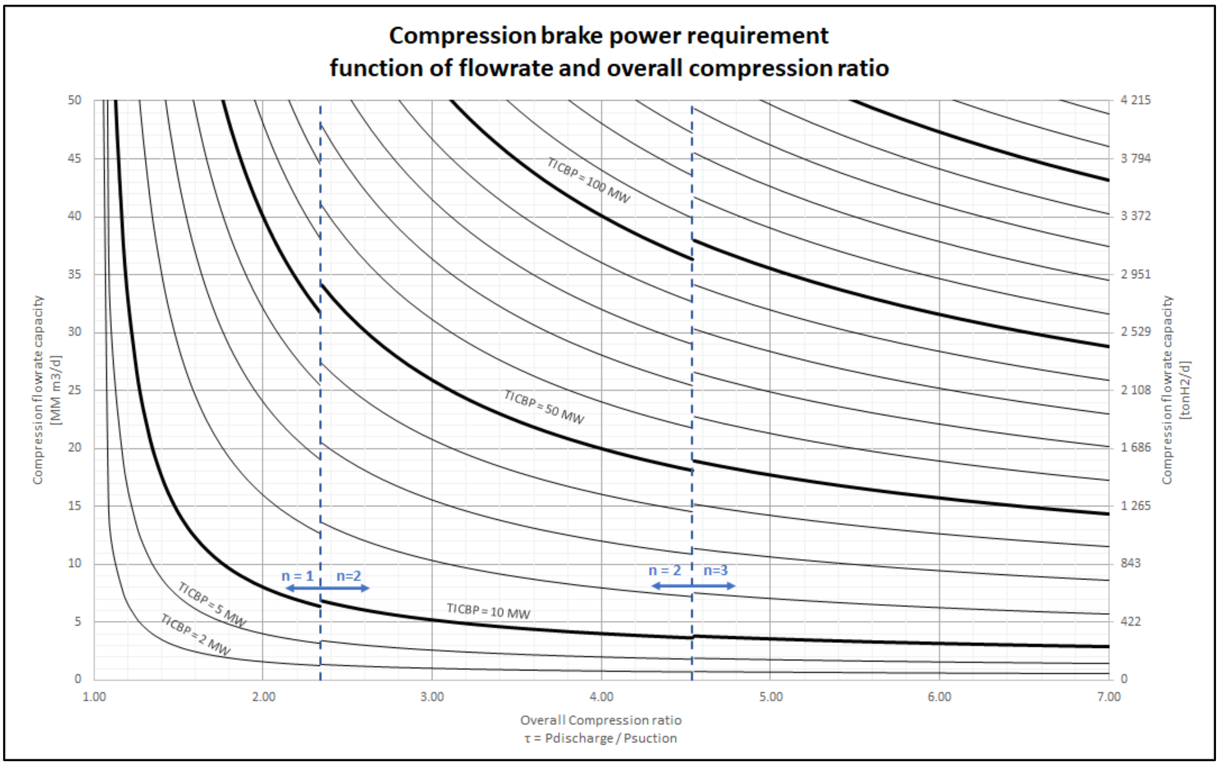
$$(4.54 < \tau \leq 9.67 \Rightarrow n = 3 \text{ for information only})$$

With

$TICBP$	[MW]	Total Installed Compression Brake Power
n	[-]	Number of required compression stages
$WTIR$	[-]	Overall withdrawal-to-Injection capacity ratio of the storage.
Q_w	[millions Sm^3 / day]	Total storage maximum withdrawal flowrate capacity
Q_i	[millions Sm^3 / day]	Overall maximum injection volume flowrate capacity
τ	[-]	Overall compression ratio (ratio of discharge pressure over suction pressure)
$netOP$	[barg]	Minimum suction pressure of compression stream (pipeline or electrolysis operating pressure)
MOP	[barg]	Maximum discharge pressure of compression stream = Maximum storage operating pressure

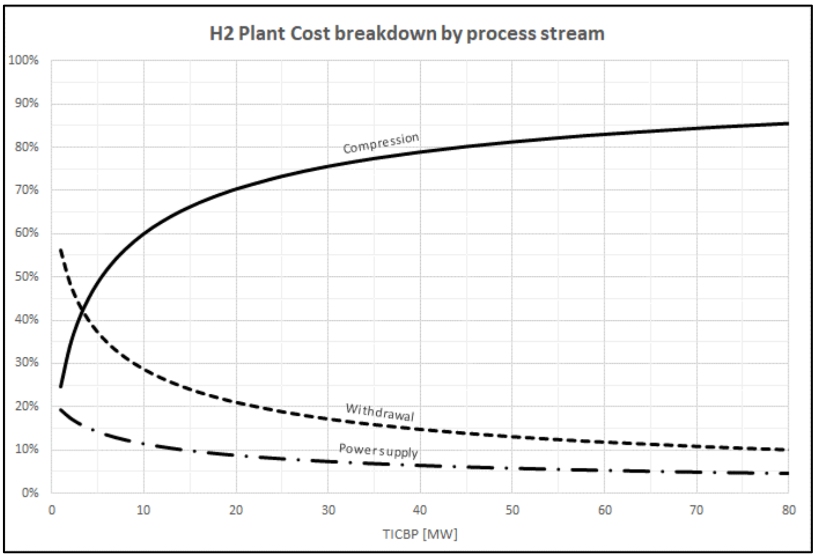
The following figure shows graphically the relation between overall compression ratio, compression design flowrate and compression brake power:

Figure 4: Compression ratio & flowrate versus compression brake power



Cost breakdown for injection stream (compression), withdrawal stream (filtering, drying and metering units), power supply and BOP is shown on the graph here below:

Figure 5: EPC cost breakdown of H_2 process plant by process stream



4.2.2. Wellpad & downstream equipment[1] and piping

EPC cost described here below are applicable for the three storage technologies: salt caverns, aquifers and depleted fields.

Interconnection between Wellheads and Gas Plant is deemed to cover the following equipment (per wellhead):

- Wellhead separators: one per WH.
- Instrumentation and valves: one set of one flowmeter, one control valve, one emergency shutdown valve and manual valves per WH.
- Well head piping: 250 metres piping per wellhead, with a design pressure of 250 barg, with flanges PN250. Size depends on minimum storage operating pressure and design flowrate per wellhead.
- Field lines: piping header, collecting gas between well pads and gas plant. Wellheads are assumed to be spaced every 500 metres. Gas plant is assumed to be 500 metres from the nearest wellhead. Piping header, with flanges PN250. Size and thickness depend on minimum and maximum storage operating pressure and maximum site design flowrate capacity.

Main parameters and EPC cost figures are summarized in the tables below:

Table 21: EPC Costs for Interconnection WH – Gas Plant

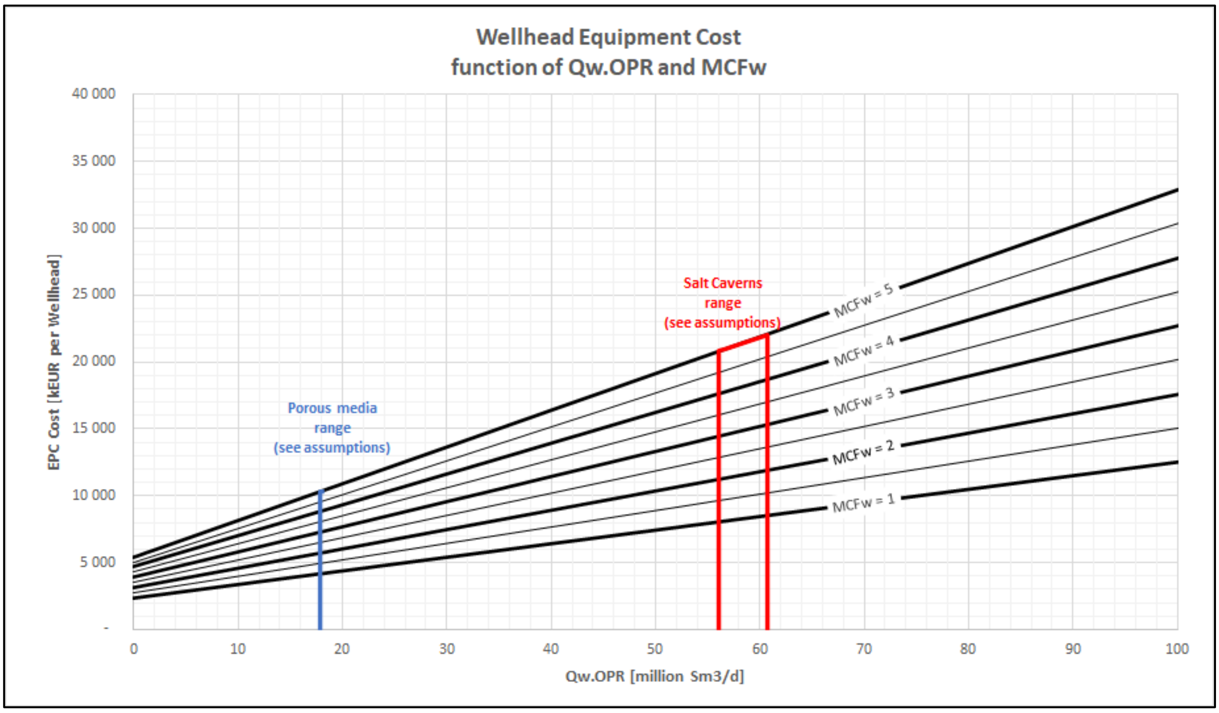
Cost drivers	Material of construction for process parts in contact with H_2	Site specific, see chapter 4.1.3
	Number of wellheads	Defined by subsurface engineering based on site conditions and geology constraints (for salt caverns, only one WH / cavern is assumed)
	Maximum storage operating pressure (=maximum injection pressure)	Site specific, see chapter 4.1.2
	Wellhead piping size and length	Various Sizes P_design = 250 barg 250 metres / WH
	Field lines size and length	Various Sizes P_design = 100-240 barg 500 metres / WH

[1] Equipment that is not part of the well pressure envelope.

<table>
<tr>
<td>EPC COST</td>
<td>EPC_2
$[k€]$</td>
<td colspan="4">$$EPC_2 = n_{WH} \cdot \begin{cases} 58.25 \cdot (1 + 74.20\% \cdot MCF_w) \cdot \mathrm{OPR} \cdot Q_w \\ +1605 \cdot (1 + 47.60\% \cdot MCF_w) \end{cases}$$
With
$\mathrm{OPR} = \frac{MOP}{minOP}$ = Operating pressure range
n_{WH} = Number of wellheads
MCF_w = Material Cost Factor for withdrawal stream
MOP = Maximum Operating Pressure of storage in [barg] see chapter 4.1.2
$minOP$ = Minimum Operating Pressure of storage in [barg] see chapter 4.1.2
Q_w = Total storage maximum withdrawal flowrate in [million Sm^3/day]</td>
</tr>
<tr>
<td>EPC Cost Breakdown</td>
<td>Engineering (EMS):
6 %-15 %</td>
<td>Procurement:
22 %-46 %</td>
<td>Construction:
36 %-58 %</td>
<td colspan="2">FEED & PMC
9%</td>
</tr>
</table>

The figure below illustrates the EPC cost for wellpad & downstream equipment, for various material cost factors:

Figure 6: EPC Cost for wellpad & downstream equipment



4.2.3. Interconnection between Wellheads and Gas Plant (Field Lines)

In the case where the hydrogen gas plant (injection and withdrawal equipment as described in chapter 4.2.1) is located at a distance above 500 metres, each additional length of piping header between Gas Plant and nearest wellhead will also have a noticeable cost impact, see table below:

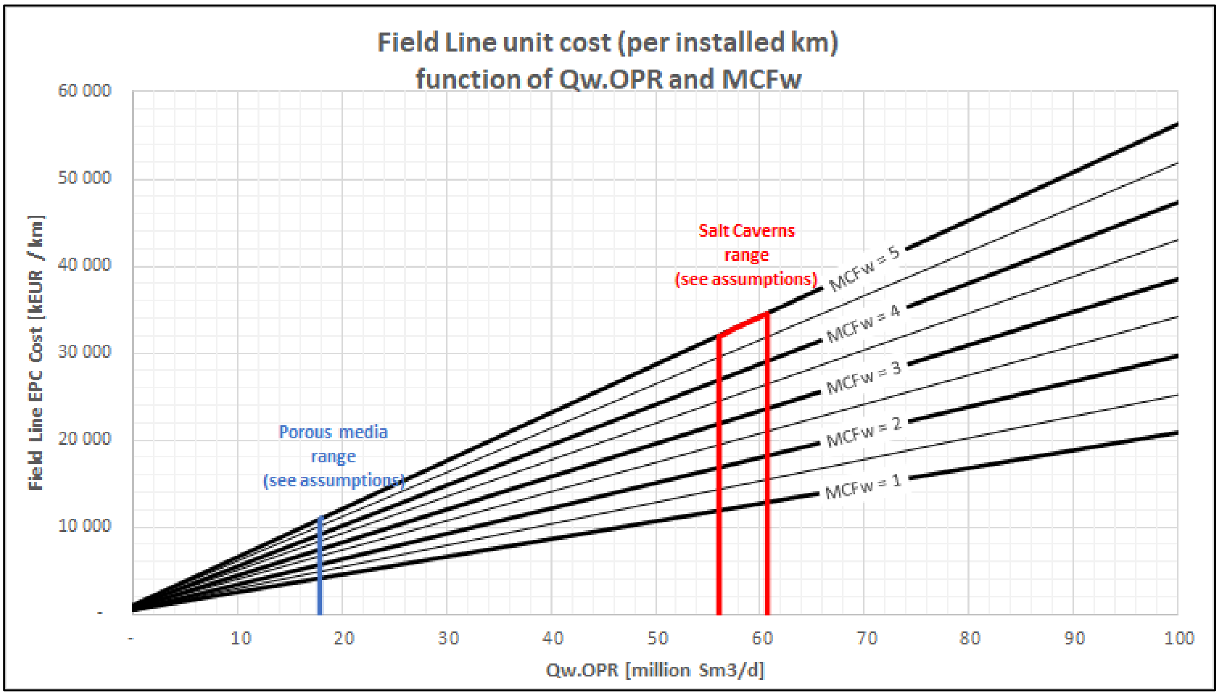
Table 22: EPC Cost per additional kilometre between Gas Plant and nearest WH

<table>
<tr><td rowspan="4">Additional cost driver</td><td colspan="2">Material of construction for process parts in contact with H_2</td><td colspan="2">Site specific, see chapter 3.1.3</td></tr>
<tr><td colspan="2">Maximum storage operating pressure (=maximum injection pressure)</td><td colspan="2">60 barg to 180 barg</td></tr>
<tr><td colspan="2">Distance between Gas plant and nearest WH</td><td colspan="2">In kilometres [km]</td></tr>
<tr><td colspan="2">Field lines size</td><td colspan="2">NPS 10” (DN250)
P_design = 180barg</td></tr>
<tr><td>EPC COST</td><td>EPC_3 $[k€]$</td><td colspan="3">$EPC_3 = 117 \cdot L_{FL} \cdot (1 + 74.30\% \cdot MCF_w) \cdot (\mathrm{OPR} \cdot Q_w + 1.90)$

With
L_{FL} = Filed Lines length in [km]
With
$\mathrm{OPR} = \frac{MOP}{minOP}$ = Storage operating pressure range
MCF_w = Material Cost Factor for withdrawal stream
MOP = Maximum Operating Pressure of storage in [barg] see chapter 4.1.2
$minOP$ = Minimum Operating Pressure of storage in [barg] see chapter 4.1.2
Q_w = Total storage maximum withdrawal flowrate in [million Sm^3/day]</td></tr>
<tr><td>EPC Cost breakdown</td><td>Engineering (EMS):
5%-9 %</td><td>Procurement:
20 %-33%</td><td>Construction:
53%-61 %</td><td>FEED & PMC
9%</td></tr>
</table>

The figure below illustrates the EPC cost for each additional kilometre of Field Lines between wellheads and gas plant, for various material cost factors:

Figure 7: EPC Cost for each additional kilometre of H2 Field Line



4.2.4. Hydrogen purification: storage impurities removal

At the storage withdrawal, depending on the storage technology, Hydrogen may need to be treated to remove impurities such as acid gases (H_2S, CO_2 etc.) and Hydrocarbons (CH_4, C_2H_6 etc.). Table here below summarises the potential main impurities by storage technology:

Table 23: Most probable impurities at storage withdrawal (in addition to H_2O)

Salt caverns	Possibly few ppm of H_2S
Aquifers	Low quantities of acid gases (H_2S, CO_2), up to hundreds of ppm
Depleted fields	Low to Medium quantities of acid gases (H_2S, CO_2) and hydrocarbons, mainly CH_4 or even heavier hydrocarbons in case of depleted oil or condensate field

The following table summarises the different existing Typical Hydrogen Purification techniques:

Table 24: Hydrogen Purification Techniques

<table>
<tr><td rowspan="8">Physical methods</td><td rowspan="3">Adsorption</td><td colspan="2">Pressure Swing Adsorption</td></tr>
<tr><td colspan="2">Temperature Swing Adsorption</td></tr>
<tr><td colspan="2">Vacuum Adsorption</td></tr>
<tr><td rowspan="2">Low Temperature Separation</td><td colspan="2">Cryogenic Distillation</td></tr>
<tr><td colspan="2">Low Temperature Adsorption</td></tr>
<tr><td rowspan="3">Membrane Separation</td><td rowspan="2">Inorganic Membrane</td><td>Metal Membrane</td></tr>
<tr><td>Carbon Molecular Sieve Membrane</td></tr>
<tr><td>Organic Membrane</td><td>Polymer Membrane</td></tr>
<tr><td rowspan="2">Chemical methods</td><td colspan="3">Metal Hybrid Separation</td></tr>
<tr><td colspan="3">Catalysis</td></tr>
</table>

The range of treatment techniques and sizing of units is very wide and dependent on too many parameters to be summarized by a simple formula or simple factors. The main design parameters impacting size and technology choice are listed here below:

- Hydrogen specification requirement at the Unit outlet (H_2 purity requirement). This requirement is dependent of the final use of hydrogen.
- Gas composition at the Unit inlet (Site specific: quantity of impurities can vary from few ppm to several percent of acid gases or HC).
- Unit inlet flowrate.
- For high H_2S load and high flowrates, Sulphur Recovery Unit may be foreseen.
- Some purification technologies may require dedicated utilities such as steam production unit.

Therefore, the costs associated with these treatment units can be only roughly estimated, based on analogy with data found in literature concerning syngas production and purification in Integrated Gasification Combined Cycle power plant for example.

Following figure proposes a range of the EPC cost of such units with respect to the treated flowrate. These costs may be added to the equipment cost of the withdrawal process stream (see chapter 4.2.1), depending on site characteristics.

Figure 8: EPC cost range for H2 purification units

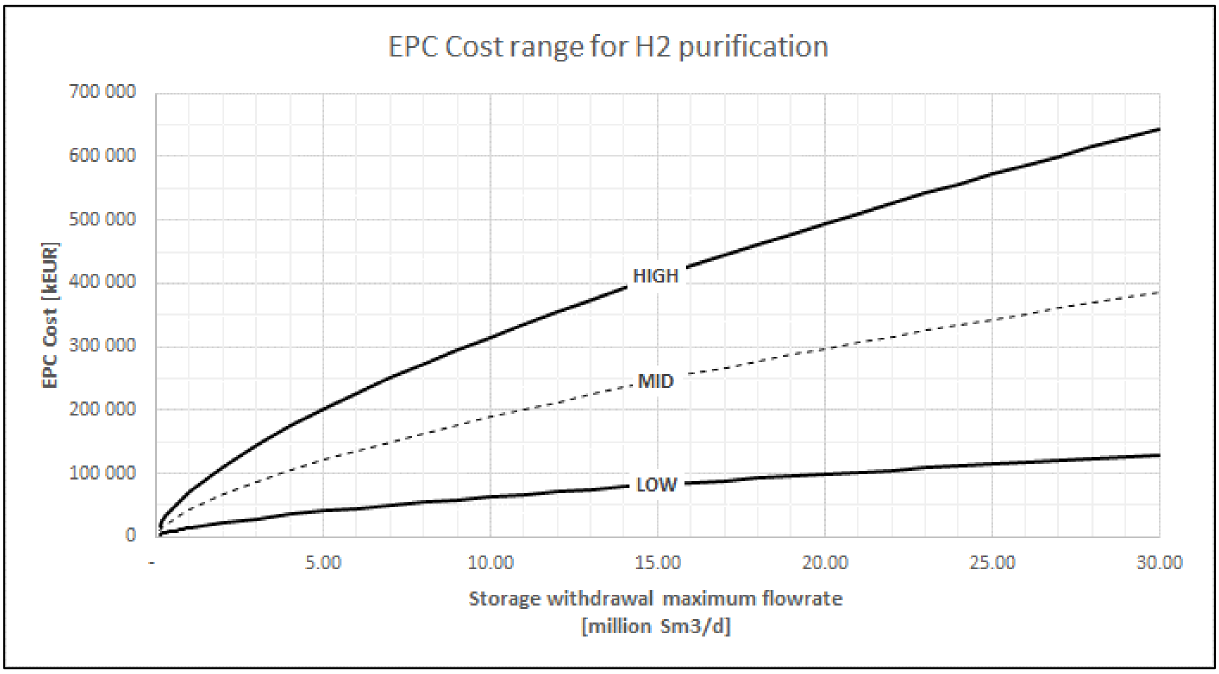


Table 25: EPC cost estimate for hydrogen purification at storage outlet (porous media)

Cost drivers	Storage maximum withdrawal flowrate H2 composition at storage WH (withdrawal phase)	
EPC COST	EPC_4 $[k€]$	$EPC_4 = K_{purif} \cdot 42\ 500 \cdot (Q_w)^{0.65}$ With Q_w = Total storage maximum withdrawal flowrate in [million Sm^3/day] K_{purif} = Coefficient depending on selected technology and contaminated hydrogen composition at storage outlet. Equal to 1.5 in base case for porous media, may vary from 1/3 up to 2 or 3 Equal 0 when purification is not required (salt caverns in first approximation)

4.2.5. Balance of Plant

Linked to the main process units, the equipment and facilities listed here below are required to operate the underground storage. For this report, Balance of Plant (BOP) is including following costs:

Table 26: Balance Of Plant – EPC Costs inclusions

Safety & Security	
	Fire water storage, firefighting pump system, its network protecting equipment and buildings
	Mobile safety and security equipment
	Fire and gas detection system
	Sirens, alarms etc.
Electrical / Instrumentation / Automatism	
	Lighting, earthing lightening
	Electrical network, including emergency power supply system
	Instrumentation liaisons
	One analyser system for gas quality
	Control and Supervisor system, Control Room equipment, Automatism
	Telecom, CCTV system
Civil Works and Buildings	
	Site preparation, earthworks, landscaping
	Rainwater/storm network
	Fences and gates
	Buildings (administrative, operation, maintenance, storage, warehouse, guard post and so on…)
	Potable water for buildings
Other utilities and auxiliaries	
	One storage unit for fuel gas used to feed the Molecular sieve regeneration and the heater, it includes metering, heating and pressure control.
	One blow-down system, and flare network or cold vent in case of emergency.
	Cathodic protection system for buried piping networks
	One Pig Trap station
	Air production unit for instruments
	Condensate and drain collection network
	Wastewater network and treatment

In first approximation, the capital costs related to BOP can be estimated as per following table:

Table 27: EPC cost main parameters and cost breakdown for Balance of Plant

Cost drivers	Independent from the site, the storage technology and size		
EPC COST	EPC_5 $[k€]$	Overall cost for Balance of Plant (BOP): $EPC_5 = 8\,000 + 5\% \cdot (EPC_1 + EPC_2 + EPC_3 + EPC_4)$	
EPC Cost breakdown	Engineering (EMS): 15%	Procurement: 38%	Construction: 47%

4.3. Contingencies for surface facilities

For this cost model, contingencies will be fixed at 20% of the following EPC costs:

- Hydrogen process plant ($\boldsymbol{EPC_1}$).
- Wellpad & downstream equipment and piping ($\boldsymbol{EPC_2}$).
- Interconnection between Wellheads (WH) and Gas Plant ($\boldsymbol{EPC_3}$).
- Hydrogen purification ($\boldsymbol{EPC_4}$)., when required.
- Balance of Plant ($\boldsymbol{EPC_5}$).

Table 28: Contingencies related to surface facilities

$\boldsymbol{CONT_{Surface}}$ $[\boldsymbol{k€}]$	$\boldsymbol{CONT_{Surface}} = \mathbf{20\%} \cdot (\boldsymbol{EPC_1} + \boldsymbol{EPC_2} + \boldsymbol{EPC_3} + \boldsymbol{EPC_4} + \boldsymbol{EPC_5})$

5. Operation costs (OPEX)

5.1. Subsurface OPEX

Similar to the surface facilities, the major subsurface operating and maintenance cost components are often a small fraction of capital costs, typically 1 to 2% including subsurface studies and surveillance activities. The following table gives an overview of the fixed and variables cost.

Table 29: Operation and maintenance cost inclusions for subsurface and wells elements

Other fixed OPEX related to subsurface		
	Well intervention team (manpower)	2% of Wells' CAPEX
	Routine Wells inspections (downhole logging for corrosion, cement bond monitoring, etc.)	
	Planned maintenance routines (annulus management, wellhead seals / tree valves greasing and testing, DHSV testing, etc.)	
	Subsurface analysis, monitoring and surveillance activities (ad hoc studies, subsidence, micro-seismic monitoring, reservoir / cavern technical follow-up)	1% of Wells' CAPEX

Table 30: Estimated Yearly Operation expenditure (OPEX)

Fixed costs	$\boldsymbol{OPEX_{UG}^{Fix}}$ $[\boldsymbol{k€/year}]$	Fixed Costs related to subsurface activities $\boldsymbol{OPEX_{UG}^{Fix}} = 3\% \cdot \boldsymbol{EPC_4^{Salt\ or\ Porous}}$

5.2. Surface OPEX

The major operating and maintenance cost components for H2 gas storage surface facilities are often a small fraction of capital costs, typically 3 to 4% excluding electricity costs. The following table gives an overview of the fixed and variables cost.

Table 31: Operation and maintenance cost inclusions

Fixed OPEX: Gas (Hydrogen) plant O&M		Assumptions
	Manpower	18 persons, including operators by shift - 1 x Gas Plant Manager - 1 x Administrative - 1 x QHSE Manager - 1 x Operation manager - 4 x Stations Operators on shift (Lead) - 4 x Stations Operators on shift (Deputy) - 1 x Maintenance Manager - 1 x Mechanical Engineer - 1 x Mechanical Technician - 1 x Control system, Elec. & Instrum. Engineer - 1 x E&I Technician - 1 x Warehouse Technician
	Staff other costs	Vehicles, lunch & transport, tools, furniture, training, IT etc.)
	Maintenance of Surface facilities	1% of CAPEX for Process facilities & BOP
	Operation (sub-contractors, technical assistance)	1% of CAPEX for Process facilities & BOP
	Insurance & taxes	2% of CAPEX for Process facilities & BOP
Variable OPEX		
	Electricity	50 to 60 EUR / MWh
	Lubricants	Assumed to be 4% of electricity cost
	Waste disposal	
	Chemicals	

OPEX depend largely on the actual as built equipment of the facility, on the performance envelope (including the required availability factor and related level of back up and maintenance) and on the hydrogen turnover.

Table 32: Estimated Yearly Operation expenditure (OPEX)

Fixed costs	$OPEX_{AG}^{Fix}$ $[k€/year]$	Fixed Costs related to H2 Gas Plant O&M: $$OPEX_{AG}^{Fix} = 2\,100 + 4\% \cdot \sum_{i=1}^{5} EPC_i$$
Variable costs	$OPEX_{AG}^{Var}$ $[k€/year]$	$$OPEX_{AG}^{Var} = 23.15 \cdot COE \cdot \frac{LF \cdot Q_w}{1 + WTIR} \cdot \left(ln(\tau) + 0.50 + K_{purif}\right)$$ With: LF = Load factor (see below) COE = Cost of electricity [€ / MWh] Q_w = Total site maximum withdrawal flowrate in [million Sm³/day] $WTIR$ = Withdrawal-to-injection capacity ratio (flowrates) $\tau = \frac{MOP+1}{netOP+1}$ = Overall compression ratio $netOP$ = Minimum suction pressure of compression stream (pipeline or electrolysis operating pressure) MOP = Maximum storage operating pressure K_{purif} = Coefficient depending on selected technology and contaminated hydrogen composition at storage outlet. Equal to 1 in base case for porous media, may vary from 1/3 up to 2 or 3. Equal 0 when purification is not required (salt caverns in first approximation)

For this cost estimation purpose, it is assumed that the storages are operated with a succession of full cycles. A full cycle is consisting of :

- One complete filling of the storage from minimum Storage Operating Pressure to maximum Storage Operating Pressure, at the maximum injection flowrate.
- Followed by completely emptying the storage from maximum Storage Operating Pressure to minimum Storage Operating Pressure, at the maximum withdrawal flowrate.

Load factor (LF) is defined here as the ratio between the number of full-cycle equivalent operation over a period N_{fc} and the maximum number N_{fc}^{MAX} of full-cycle equivalent achievable over the same duration.

$$0\% \leq LF = \frac{N_{fc}}{N_{fc}^{MAX}} \leq 100\%$$

To give an order of magnitude, the duration of one full-cycle operation can be estimated by:

$$d_{full\ cycle}[days] = \frac{V_{WG}}{Q_w}(1 + WTIR)$$

Then the maximum number of full cycles per year can be deducted by:

$$N_{fc}^{MAX} = \frac{365}{d_{full\ cycle}}$$

With

$d_{full\ cycle}$	[days]	Duration of one full cycle of the storage
V_{WG}	[million Sm³]	Total working gas volume
Q_w	[million Sm³/day]	Maximum withdrawal flowrate
$WTIR$	[-]	Withdrawal-to-injection capacity ratio (flowrates)
N_{fc}^{MAX}	[-]	Maximum number of full cycles per year

6. Abandonment costs (ABEX)

6.1. Subsurface ABEX

Extensive studies and research works have been performed for the last thirty years on the subject of cavern abandonment and post mining lessons have led to useful concepts to be almost accepted at international level: standard No. EN 1918-3 -project still being discussed- or SMRI report Crotogino and Kepplinger, 2006.

From these references, the final closure of a storage plant must be considered for each location, with special attention paid to long term integrity. In the case of the abandonment of one or several wells during operation, similar procedures for plugging and abandoning wells have to be applied. Moreover, the permanent closure must be considered separately for each cavern. The studies and measurements must prove the safety of the condition left after abandonment.

The common practice of the industry has established the following list of requirements at the end of the storage operations (Crotogino and Kepplinger, 2006):

- long-term protection from contamination of drinking water aquifers and the escape of brine and / or flammable product residues to the surface,
- long-term stability of the rock mass surrounding the cavern,
- maintenance-free,
- affordability,
- acceptability by the authorities.

The first two objectives will be fulfilled at the brine cavern stage, whereas maintenance-free cavern will begin after the final cavern abandonment.

Typically, the storage caverns will be decommissioned by snubbing in a water injection string and removing the gas by pumping water or brine back into the cavities. When fully saturated, this will prevent any further salt from being dissolved.

Aboveground the gas wellhead will be replaced by a standard brine wellhead. The wellheads will remain so that cavities can be monitored and surveyed to ensure future stability.

The permanent abandonment is undertaken only after a full cavern thermal stabilization is obtained. It will consist of cementing the well (permanent sealing of the brine in the cavern), removing the wellhead and the casing two (2) metres below ground level and restoring the surface soil.

The above-mentioned abandonment procedures are summarized from salt cavern storage industry standards. Abandonment of a storage salt cavern implies operations, such as re-filling the cavern with brine, and durations, required to achieve a sufficient thermal stabilization, that are not relevant for the abandonment of aquifer or depleted field storage. However, the cushion gas can be recovered when re-brining a salt cavern. This cushion gas may still have a commercial value, although this can hardly be assessed quantitatively to date. We assume that the operations and waiting time specific to salt cavern abandonment are balanced by the fact that cushion gas can be recovered, and consider a single decommissioning cost for salt caverns, depleted fields and aquifers.

Like for surface facilities, it is estimated that subsurface ABEX typically falls within a range of 10 to 30% of subsurface CAPEX.

It is proposed to assume 20% of total subsurface facilities CAPEX. Subsurface facilities CAPEX will aggregate the CAPEX costs for:

- Salt caverns
    - Development drilling and leaching completion costs ($\boldsymbol{EPC_4^{Salt}}$)
    - Leaching plant EPC costs ($\boldsymbol{EPC_1^{Salt}}$)
    - Leaching operation and maintenance costs ($\boldsymbol{EPC_2^{Salt}}$)
    - Salt cavern conversion cost – Debrining & First Gas Fill ($\boldsymbol{EPC_3^{Salt}}$)
    - Contingencies ($\boldsymbol{CONT_{Subsurface}^{Salt}}$)

- Porous media
    - Development drilling ($\boldsymbol{EPC_4^{Porous}}$)
    - First gas fill (FGF) of porous media ($\boldsymbol{EPC_3^{Porous}}$)
    - Contingencies ($\boldsymbol{CONT_{Subsurface}^{Porous}}$)

Total subsurface facilities ABEX is calculated as follows:

Table 33: ABEX related to subsurface

$\boldsymbol{ABEX_{Subsurface}}$	$\boldsymbol{ABEX_{Subsurface}^{Salt} = 20\% \cdot (EPC_1^{Salt} + EPC_2^{Salt} + EPC_3^{Salt} + EPC_4^{Salt} + CONT_{Subsurface}^{Salt})}$ $\boldsymbol{ABEX_{Subsurface}^{Porous} = 20\% \cdot (EPC_3^{Porous} + EPC_4^{Porous} + CONT_{Subsurface}^{Porous})}$

Note: It should be noted that part or totality of cushion gas may be recovered at the end of the operating life of the underground gas storage. This means that a part of the initial invested CAPEX will be recovered at that time. However, considering the uncertainties on its valorisation and volume, this has not been considered in the ABEX estimate.

6.2. Surface facilities ABEX

For surface facilities, ABEX estimates typically fall within a range of 10 to 30% of CAPEX.

It is proposed to take 20% of total surface facilities CAPEX. Surface facilities CAPEX will aggregate the CAPEX costs for:

- Hydrogen process plant ($\boldsymbol{EPC_1}$).
- Wellhead equipment and piping ($\boldsymbol{EPC_2}$).
- Interconnection between Wellheads (WH) and Gas Plant ($\boldsymbol{EPC_3}$).
- Hydrogen purification ($\boldsymbol{EPC_4}$)., when required.
- Balance of Plant ($\boldsymbol{EPC_5}$).
- Contingencies ($\boldsymbol{CONT_{Surface}}$)

Total surface facilities ABEX is calculated as follows:

Table 34: ABEX related to surface facilities

$\boldsymbol{ABEX_{Surface}}$	$\boldsymbol{ABEX_{Surface}} = \mathbf{20\%} \cdot (\boldsymbol{EPC_1} + \boldsymbol{EPC_2} + \boldsymbol{EPC_3} + \boldsymbol{EPC_4} + \boldsymbol{EPC_5} + \boldsymbol{CONT_{Surface}})$

7. Life Cycle Cost Assessment

Based on the model described in preceding chapters, total CAPEX, variable yearly OPEX and fixed yearly OPEX and ABEX for both surface and sub-surface facilities have been estimated for typical storages (refer to conceptual design cases definition in deliverable D7.1), with:

- Storage capacity for salt caverns around 250 million Sm^3 i.e. 21 000 tons H_2 or 700 GWh_LHV.
- Storage capacity for porous media around 550 million Sm^3 i.e. 46 500 tons H_2 or 1 550 GWh_LHV.
- Storage and surface facilities located onshore.
- Maximum withdrawal flowrate Qw as defined in deliverable D7.1 and chapter 4.1.2, Table 18.
- Typical $WTIR$ (maximum withdrawal-to-injection flowrate ratio) varying between 1 and 5.
- Compression stream material = Carbon Steel ($\boldsymbol{MCF_i = 1}$)
- Withdrawal stream material = Carbon Steel for both salt caverns and porous media storages ($\boldsymbol{MCF_w = 1}$), see note [2] below.
- Purification facilities for porous media with $K_{purif}^{Porous} = 1.5$; no purification unit for salt caverns with $K_{purif}^{Salt} = 0$ (refer to chapter 7.4).
- Cost of electricity (COE) has been set at 60 EUR / MWh.

In addition to the parameters listed in Table 18, the following input parameters are considered for the analysis:

Table 35: Other model input parameters assumptions

DESCRIPTION	Parameter name	Unit	Value
Distance nearest WH – Gas Plant	$\boldsymbol{L_{FL}}$	[km]	2
Fresh water pipeline	$\boldsymbol{L_{FW}}$	[km]	15
Brine disposal pipeline length	$\boldsymbol{L_{BD}}$	[km]	30
Debrining flowrate, per cavern	$\boldsymbol{Q_{debrining}}$	[m^3/hr]	200
Hydrogen cost	$\boldsymbol{H_2Cost}$	[EUR/kg]	2.00
Drilling complexity index	$\boldsymbol{DCi}$	[-]	1.0
Minimum suction pressure of compression stream	$\boldsymbol{netOP}$	[barg]	55

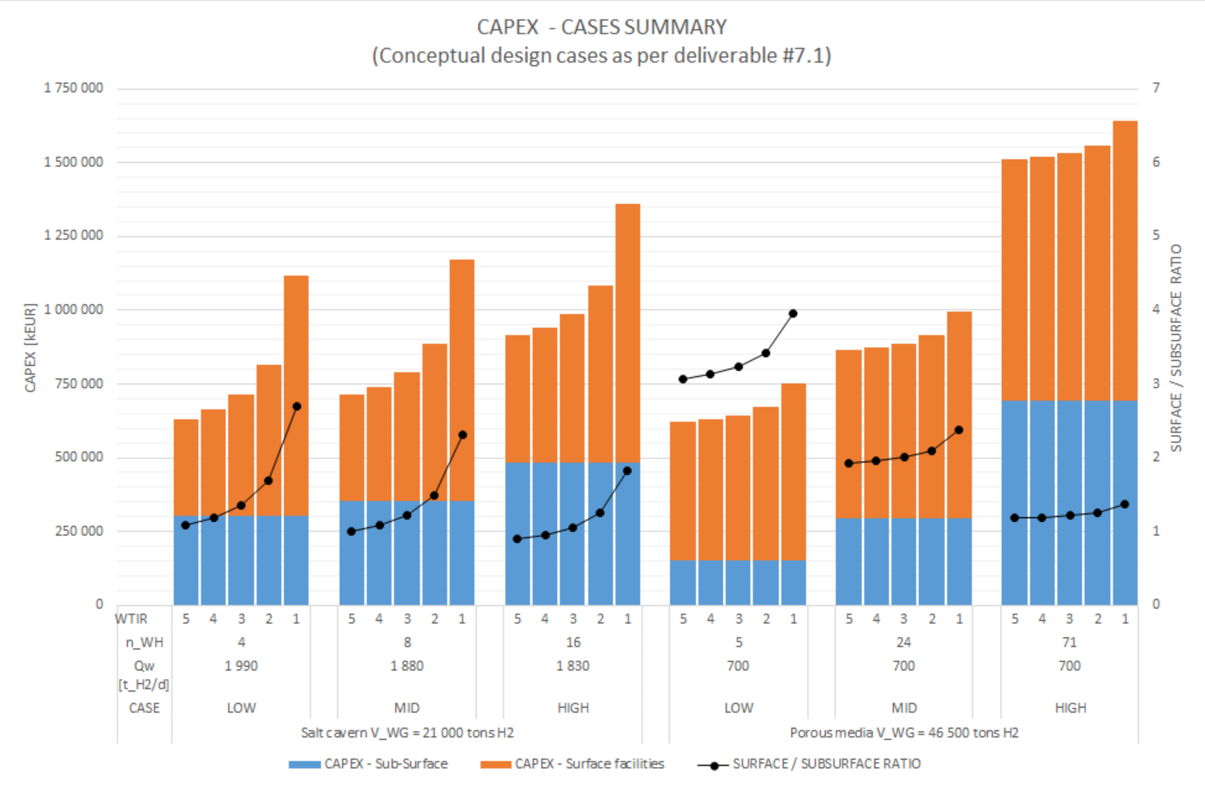
[2] **material assumption for H_2 wet streams equipment**:

Above assumptions are based on current knowledge and on conceptual design D7.1. Material choice may vary due to results from ongoing works (WP4 and other research project focused on material resistance to hydrogen) and from site specificities. Especially for porous media, material choice shall consider withdrawal gas composition.

7.1. CAPEX analysis

The application of CAPEX model formulas developed in previous chapters are compiled in the following chart:

Figure 9: Conceptual design case study - CAPEX summary



These figures related to CAPEX, OPEX and ABEX are discussed more in detail in the following sub-chapters.

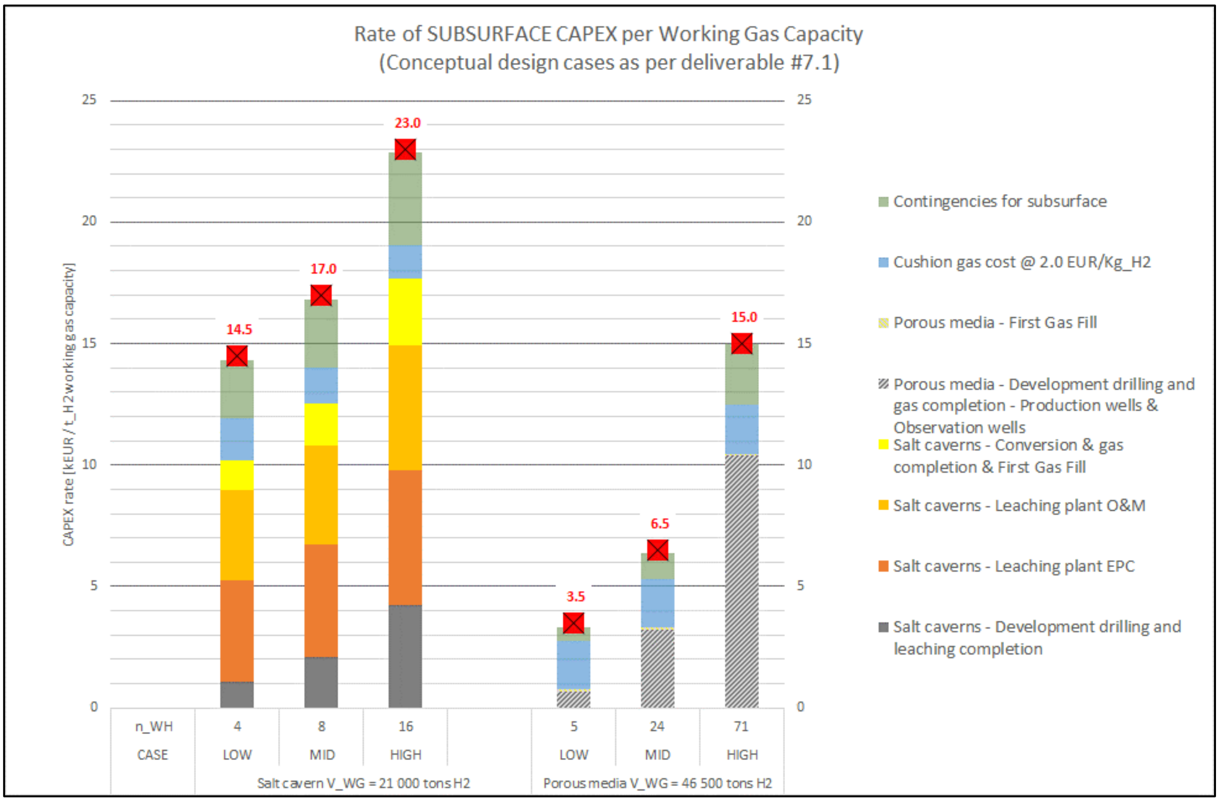
7.1.1. CAPEX RATE per volume capacity (subsurface)

At early stage of a project, such as conceptual step, subsurface facilities main sizing parameters are:

- V_{WG}, the targeted working gas volume of the storage constrained by local geology.
- n_{WH}, the number of production wells to be drilled, to obtain both the targeted storage volume and the withdrawal flowrate capacity, constrained by local geology.
- $LCCS$, the depth of last cemented casing shoe, which is linked to the overall storage depth.
- MCF, the material cost factor, reflecting the material used for casings and/or completion equipment of the well. This parameter is constrained by metallurgy, by fluid composition and by operating conditions (pressure and temperature).

To make things comparable, the CAPEX for subsurface facilities, related to different underground storage technologies, are reduced to unit working gas capacity. The subsurface CAPEX model described in chapter 3, allows to build the following chart:

Figure 10: Sub-surface CAPEX RATE per storage volume capacity (working gas) – cases as per deliverable #7.1



It shall be noted that the CAPEX rates resulting from this assessment are highly dependent on the number of wells required to obtain the target working gas capacity together with the withdrawal flowrate capacity.

In particular, the relatively large spread of results in the case of porous media (depleted and aquifers) is a direct result of the statistical analysis conducted as part of the conceptual design presented deliverable D7.1, with a relatively wide range in the well count between the low case and the high case. This is somewhat something that one could expect and that simply reflects the significant level of subsurface uncertainty that may exist for aquifers and depleted fields (reservoir connectivity, formation heterogeneity, and other multiple factors that will drive the well count to achieve specific goals regarding working gas volume and maximum withdrawal rates).

For conceptual phase of site development or early business strategy study, the values proposed in the following table could be taken as reference for subsurface facilities CAPEX assessment, based on MID case for each technology:

Table 36: Subsurface facilities CAPEX rate – Order of magnitude (MID case basis of deliverable #7.1)

SUBSURFACE CAPEX RATE UNIT: kEUR per working gas capacity	SALT CAVERNS	POROUS MEDIA
kEUR per ton_H_2 *[Range]*	17 *[14.5 – 23]*	6.50 *[3.5 - 15]*
kEUR per million Sm^3 *[Range]*	1 430 *[1 220 - 1 940]*	550 *[295 - 1265]*
EUR per KWh_H_2(LHV) ***[Range]***	**0.51** ***[0.44 – 0.69]***	**0.20** ***[0.11 – 0.45]***

7.1.2. CAPEX RATE per withdrawal flowrate capacity (surface)

At early stage of a project, such as conceptual step, surface facilities main sizing parameters are:

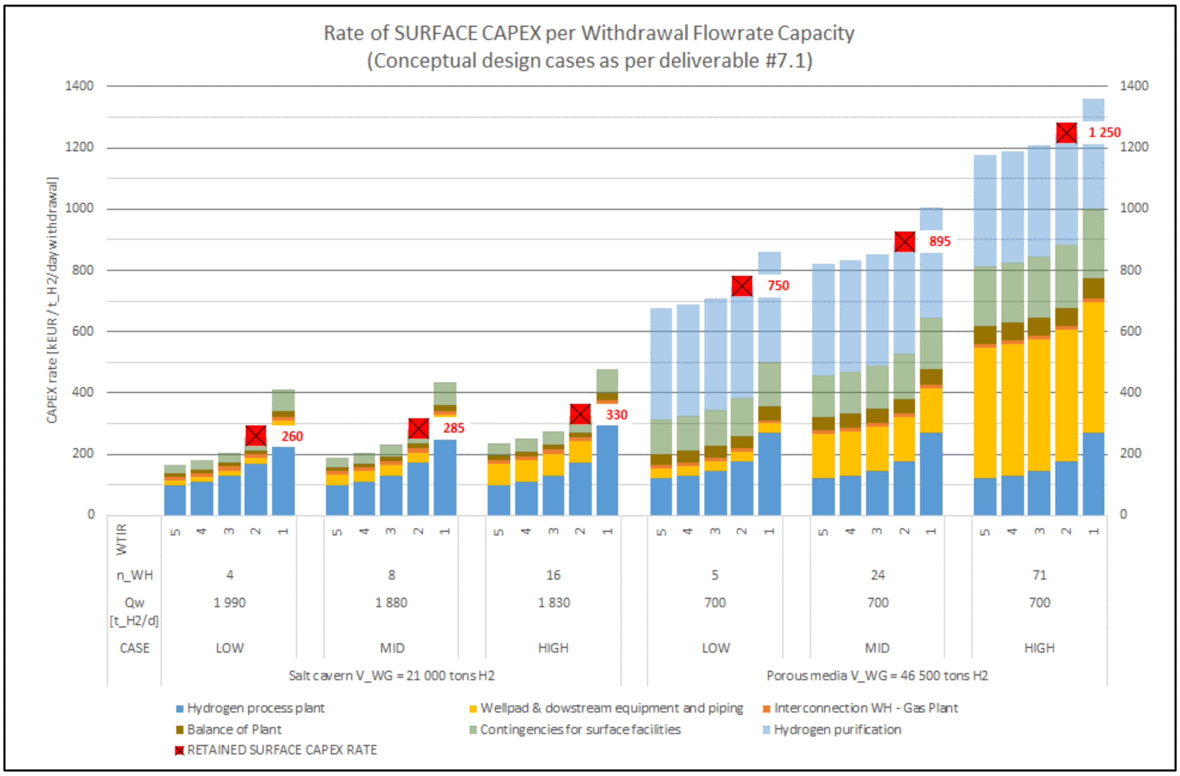
- Q_w, the maximum storage withdrawal flowrate, which leads to withdrawal stream equipment sizing.
- $WTIR$, the maximum withdrawal-to-injection flowrate ratio, which leads to compression equipment sizing through $Q_i = Q_w/WTIR$, the maximum injection flowrate.
- MCF, the material cost factor, reflecting the material used for process parts in contact with Hydrogen. This parameter is constrained by metallurgy, by fluid composition and by operating conditions (pressure and temperature).
- OPR, the Operating Pressure Range, equal to the ratio of MOP, maximum storage operating pressure over $minOP$, the minimum storage operating pressure. This parameter is constrained by local geology for safe operation of the underground storages. This parameter is linked to the maximum storage capacity.
- K_{purif}, the coefficient depending on selected technology for H_2 purification and contaminated hydrogen composition at storage outlet.

Q_w is the key differentiating parameter between underground technologies, as far as the surface facilities are concerned. It is commonly set at the physical maximum capacity allowed by site geological properties for safe operation of the storage. For salt caverns, it will be constrained by the maximum pressure change rate. For porous media storages, the maximum withdrawal flowrate will depend on reservoir properties and well productivity.

WTIR is a techno-economic parameter set by defining the cycling with injection / withdrawal cycles based on business needs and storage operation strategy.

To make things comparable, the CAPEX for surface facilities, related to different underground storage technologies, are reduced to unit withdrawal flowrate capacity. The surface CAPEX model described in chapter 4, allows to build the following chart:

Figure 11: Surface CAPEX RATE per withdrawal flowrate capacity



For conceptual phase of site development or early business strategy study, the values proposed in the following table could be taken as reference for surface facilities CAPEX assessment, based for each technology, on MID case with WTIR = 2.

Table 37: Surface facilities CAPEX rate – Order of magnitude

SURFACE CAPEX RATE UNIT: kEUR per withdrawal max. capacity	SALT CAVERNS	POROUS MEDIA
kEUR per ton_H_2/day	285	895
kEUR per million Sm^3/day	24 000	75 500
EUR per kW_H_2(LHV)	**205**	**645**

7.2. OPEX analysis

7.2.1. VARIABLE OPEX RATE per volume cycled

To make things comparable, the yearly VARIABLE OPEX for surface facilities, related to different underground storage technologies, are reduced to unit quantity of hydrogen passing through the storage facilities each year:

$$VARIABLE\ OPEX\ RATE_{[EUR/ton_{H2}]} = 1000 \cdot \frac{OPEX_{AG}^{Var}{}_{[kEUR/year]}}{V_{cumul}{}_{[ton_{H2}/year]}}$$

The cumulated quantity of hydrogen passing through the storage over a year V_{cumul} is equal to the number of equivalent full cycle per year of the storage times the working gas capacity:

$$V_{cumul}{}_{[MM\ Sm^3/year]} = N_{fc} \cdot V_{WG} = \left(N_{fc}^{MAX} \cdot LF\right) \cdot V_{WG} = \frac{365 \cdot\ LF \cdot V_{WG}}{d_{full\ cycle}} = \frac{365 \cdot\ LF \cdot V_{WG}}{\frac{V_{WG}}{Q_w}(1 + WTIR)}$$

Thereby, it can be assumed that V_{cumul} depends only on the maximum withdrawal flowrate Q_w, the Load Factor LF and the withdrawal-to-injection capacity ratio $WTIR$:

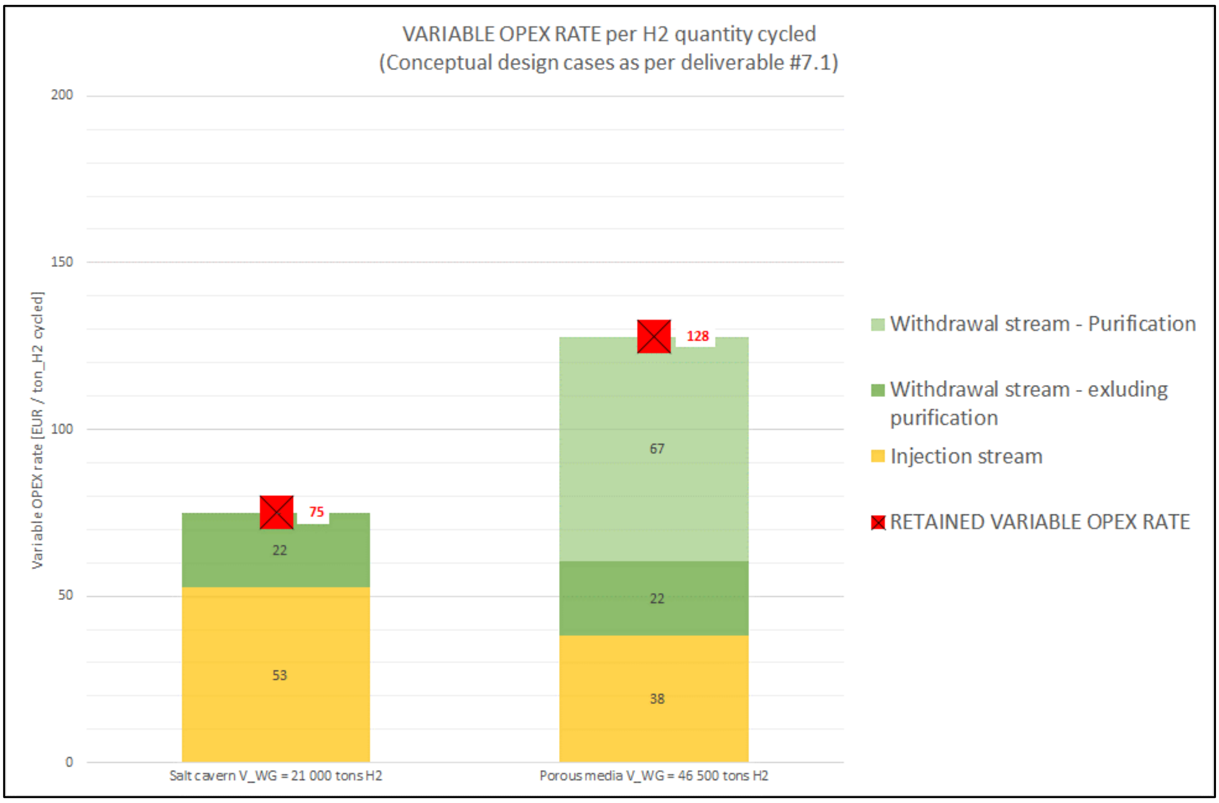
$$V_{cumul}{}_{[ton_{H2}/year]} = 365 \cdot \frac{LF \cdot Q_w}{1 + WTIR} \cdot 85_{[ton_{H2}/million\ Sm^3]}$$

It comes then that the $VARIABLE\ OPEX\ RATE$ can be expressed as a function of Cost of Electricity COE, overall compression ratio τ and the need of purification (parameter K_{purif}). It is independent from LF, $WTIR$ and initial CAPEX:

$$\boldsymbol{VARIABLE\ OPEX\ RATE_{[EUR/ton_{H2}]} = 0.746 \cdot COE \cdot (ln(\tau) + 0.50 + K\_purif)}$$

The following figure is compiling the results corresponding to the conceptual design of deliverable #7.1 and previous chapters 4 and 5.2:

Figure 12: Variable OPEX RATE per H2 volume cycled



For conceptual phase of site development or early business strategy study, the values proposed in the following table could be taken as reference for the yearly VARIABLE OPEX assessment.

Table 38: Surface facilities VARIABLE OPEX RATE – Order of magnitude

VARIABLE OPEX RATE For COE = 60 EUR/MWh UNIT: EUR per cycled quantity	**SALT CAVERNS**	**POROUS MEDIA**
EUR per ton_H_2	75	128
EUR per million Sm^3	6 300	10 750
EUR per MWh_H_2(LHV)	**2.25**	**3.83**

7.2.2. FIXED OPEX RATE per related CAPEX

To make things comparable, the yearly FIXED OPEX, related to different underground storage technologies, are expressed as a percentage of the related CAPEX:

$$SURFACE\ FIXED\ OPEX\ RATE_{[\%CAPEX/year]} = \frac{OPEX_{AG\ [kEUR/year]}^{Fix}}{CAPEX_{AG\,[kEUR]}}$$

With $CAPEX_{AG\,[kEUR]} = EPC_1 + EPC_2 + EPC_3 + EPC_4 + EPC_5 + CONT_{Surface}$

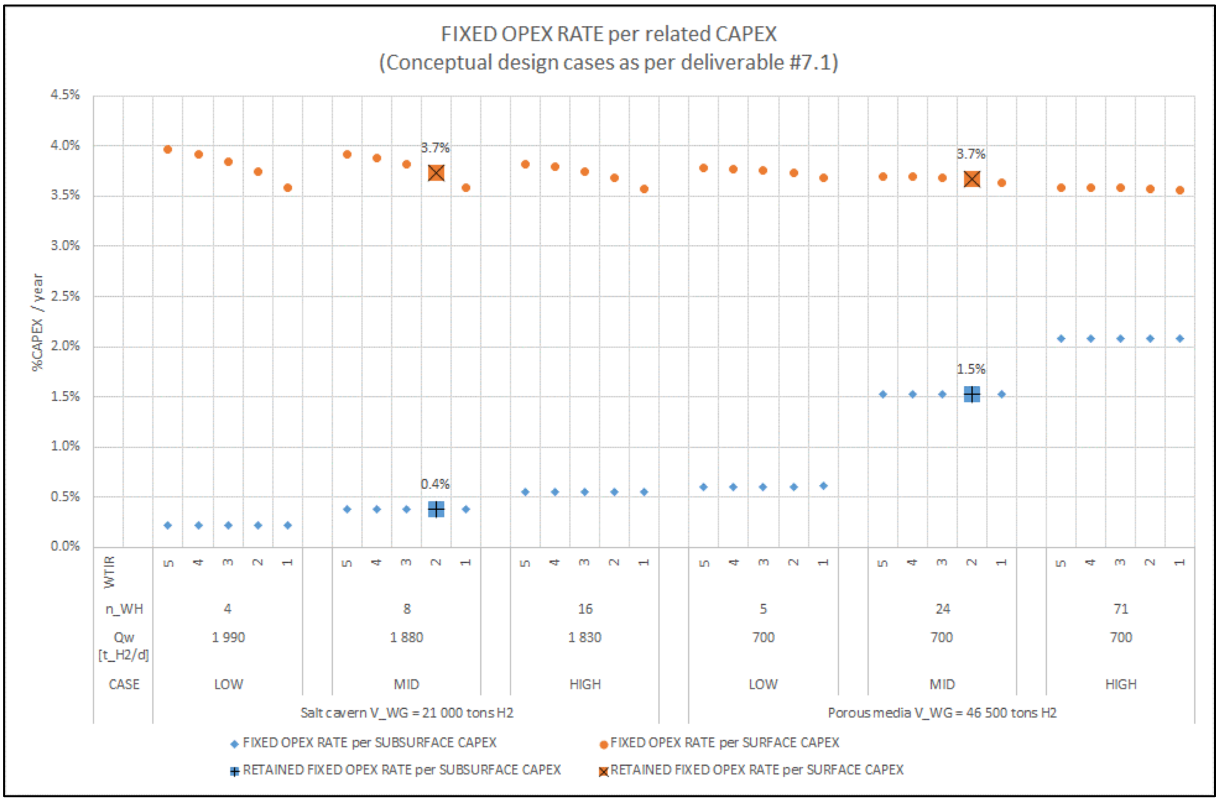
And:

$$SUBSURFACE\ FIXED\ OPEX\ RATE_{[\%CAPEX/year]} = \frac{OPEX_{UG\ [kEUR/year]}^{Fix}}{CAPEX_{UG\,[kEUR]}}$$

$$\text{With } CAPEX_{UG\,[kEUR]} = \begin{cases} EPC_1^{Salt} + EPC_2^{Salt} + EPC_3^{Salt} + EPC_4^{Salt} + CG^{Salt} + CONT_{Subsurface}^{Salt} \\ or \\ EPC_3^{Porous} + EPC_4^{Porous} + CG^{Porous} + CONT_{Subsurface}^{Porous} \end{cases}$$

The following figure is compiling the results corresponding to the conceptual design of deliverable #7.1 and previous chapters:

Figure 13: FIXED OPEX RATE per related CAPEX



For conceptual phase of site development or early business strategy study, the values proposed in the following table could be taken as reference for the yearly VARIABLE OPEX assessment.

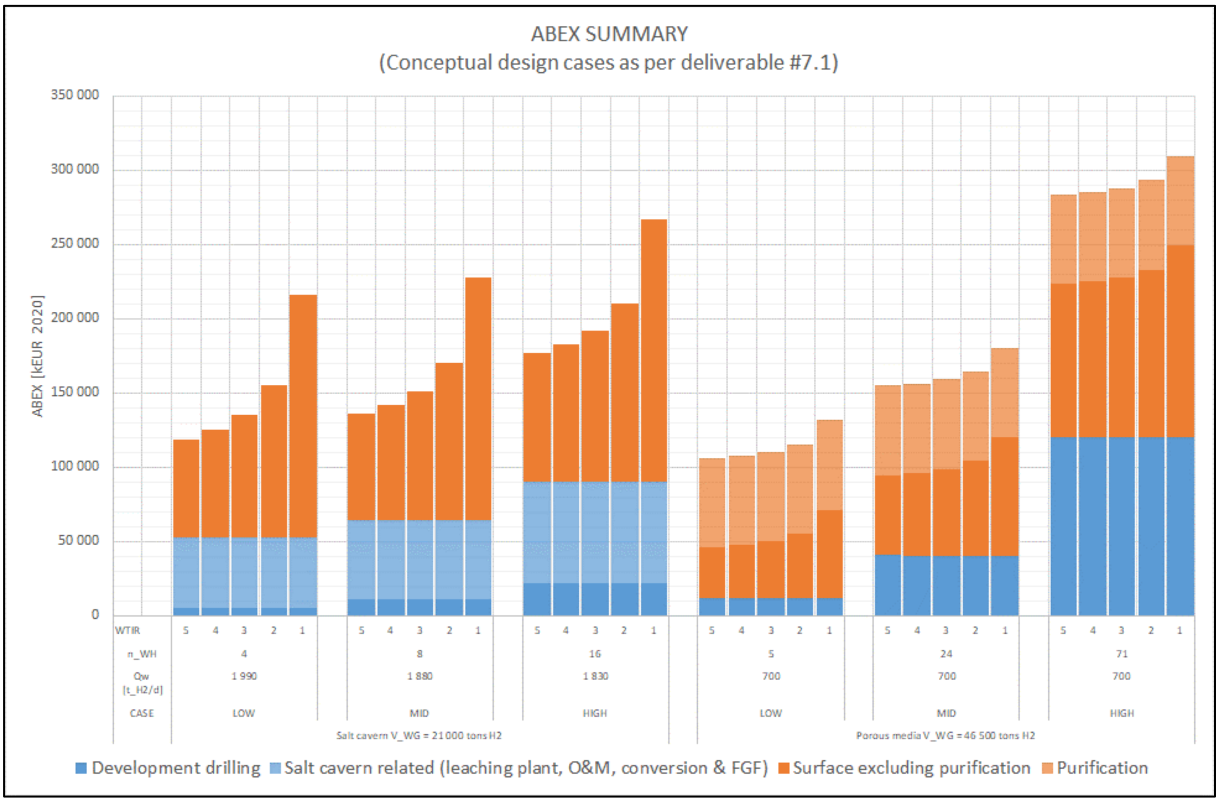
Table 39: FIXED OPEX RATE per related CAPEX – Order of magnitude

FIXED OPEX RATE UNIT : % of related CAPEX / year	SALT CAVERNS	POROUS MEDIA
% Surface CAPEX / year	**3.7%**	**3.7%**
% Subsurface CAPEX / year	**0.4%**	**1.5%**

7.3. ABEX analysis

ABEX is deemed to be proportional to initial related CAPEX. On the following chart, ABEX is expressed in EURO 2020, without discount rate over the storage lifetime.

Figure 14: Conceptual design case study - ABEX summary in EUR 2020



ABEX are usually spent at the end of storage life. Nevertheless, it shall be kept in mind the following:

- For salt caverns: ABEX part related to leaching plant may be anticipated, partially or totally,
- For porous media: wells may be abandoned gradually over the lifetime of the site.

7.4. Stored gas losses

For both salt cavern and porous media storage, the absence of significant gas leakage outside of the storage has been established through the use of these underground storages for storing natural gas since 1915 (depleted field in Canada), 1940 (aquifer in the USA) or 1961 (salt cavern in the USA). Today, 10 % of the annual natural gas production is stored in these types of underground storages. No loss of stored gas to the outside of the storage is expected for hydrogen either. We note that in the case of salt caverns, the tightness of the underground storage can also be accurately tested; it has become a standard ("Mechanical Integrity Tests") and is proposed for hydrogen storage, as presented in Bérest et al., 2021.

The question of the stored gas losses falls into the consumption of hydrogen by geochemical reactions and microbiological activity. This is the focus of the following two sections. The abiotic chemical reaction in porous media are studied and detailed in WP2 of Hystories, while the microbiological reactions in porous media and their impacts are studied in WP3.

Literature (e.g. Panfilov, 2015; Heinemann et al., 2021; Ineris, 2021) suggests that hydrogen is a strong oxidizer and reactions are thermodynamically possible, although abiotic reaction should not happen under storage temperatures besides rare cases, such as when pyrite is among the reservoir rocks. But a wide range of bacteria can catalyse these thermodynamically possible reactions to convert part of this potential energy to cellular energy. This can be possibly significant at reservoir scale. Among others, the reaction of hydrogen and CO_2 to methane (methanogenesis) and the reaction of hydrogen and sulfur to hydrogen sulfide are possible. This section will not detail these phenomena, which will be done in these WP2 and WP3 deliverables, but aims at proposing an early estimate of the impact at storage scale for economic modelling purpose. The focus of this section is the quantification in terms of the loss of product, itself based on the likelihood of having noticeable effects of the microbiological activity on the stored product composition, and the magnitude of the impact when happening. This estimation is meant to give an order of magnitude for a general, or conceptual design, whereas these processes are highly site-specific; it should therefore not be taken as a reliable result for a given site. It is based on a literature review and lessons learnt from analogues, for porous media and salt caverns.

7.4.1. Salt caverns

The fact that microbiological activity in the residual brine of a salt cavern storing hydrocarbons can create a contamination of the stored product is known to be possible. Extreme halophilic thiosulfate reducing bacteria (TRB) were found to proliferate in saturated salt cavern brines (Dieterich et al., 2011; Fournier et al., 2020). From Geostock experience, H_2S production due to this activity happens or have happened in at least 1 natural gas storage site and 1 hydrocarbon storage site, which is rare when compared to the hundreds of storage caverns over which Geostock is or has recently been working. On these specific sites, in-situ treatments have been investigated as exposed in Fournier et al. (2020) and sometimes applied but feedback on long term efficiency of the treatments is not available. From this analogue experience of hydrocarbon storage in salt cavern, we note that the microbiological activity is not a question of product loss, possibly a question of product quality.

In the case of hydrogen storage cavern, it is established in the literature (Panfilov, 2016; Dopffel et al., 2021, Réveillère et al., 2022) that microbiological activity will happen in the brine with dissolved hydrogen. The question of its impact at industrial scale is harder to find in the academic literature. In the public information from the 6 existing Hydrogen caverns operating for sometimes more than 50 years, there is no mention of loss of the stored hydrogen by geochemical reactions or microbiological activity. There is in general limited public information on the quality of the withdrawn gas, besides the following two from Air Liquide, the operator of the Spindeltop cavern that started operating in 2014. Jallais (2021) mentions "No pollution & contamination of the gas" among advantages of Salt cavern storage of hydrogen. The same author considers a "Purification unit" in the surface equipment of an H_2 storage site in salt cavern, but associates a "negligeable" cost to it in Ineris, 2021. Through a personal communication with the operator of a H_2 storage cavern, the feedback was that they detected H_2S in the withdrawn gas at the beginning, and that it went away without any action on their end. The fact that another hydrogen cavern had detected H_2S was also mentioned. From these feedbacks we note that the impact of the microbiological activity is not a question of product loss, possibly a question of product quality, and that it is probably much more common for hydrogen than it is for hydrocarbon storage caverns.

Estimations of the impacts of microbiological activity in salt caverns storing hydrogen at cavern scale derived from modelling approaches are hardly found in the public literature. Laban (2020) has done this exercise in his Masters' Thesis, which implied simplifying the reactions that can occur, applying kinetic rates from the literature, and then upscaling the batch result to the cavern scale. The author has found that a first case leads to 0.04 ppm of H_2S production, and the other up to 24 ppm, or 0.0024%, after 10 years. This is a hydrogen consumption that may require treatment, but it is not a significant hydrogen loss.

The following table summarizes the findings from these analogues.

Table 40: Synthesis of the likelihood and severity of hydrogen contamination in salt caverns from past experience, analogues and modelling works

Reference	Occurrence of noticeable effect of the microbiological activity	Severity when happening	Remark
Hydrocarbon storage analogue	A few percent of the caverns	Purity question, no product loss	There is no dissolved hydrogen. This is only suggesting that microorganisms can have an impact noticeable at cavern scale.
Pure hydrogen storage experience	Unclear, possibly up to half of the caverns	Purity question, no product loss Purification cost is "negligeable"	Only 3 American H2 caverns are direct analogues. The 3 British H2 caverns are storing H2 with CO2, providing a constant source of carbonates, which would make results less comparable. Of these caverns, 2 would have had H_2S detected, without requiring any treatment action to be implemented, and this was not necessarily due to microbial activity only
Modelling and impact assessment up to cavern scale	N/A	Purity question, no product loss	Only 1 modelling exercise suggesting a max H_2S concentration of 0.0024 % (Laban, 2020)

From these elements, we assume that the losses when storing hydrogen in salt caverns is 0%, corresponding to no significant loss. There may be a requirement for purification, but its cost is not considered either, as it is judged "negligeable" by one the companies operating a storage, and as the H_2S production may disappear.

Table 41: Hydrogen losses in Salt caverns storage

$\boldsymbol{H_2Loss_{Salt}}$	$\boldsymbol{H_2Loss_{Salt}} = \left(\frac{Injected\ working\ gas - Withdrawn\ gas}{Injected\ working\ gas}\right) = \mathbf{0}\%$

7.4.2. Porous media

As in the salt cavern storage, the hydrogen gas injected into a porous reservoir may trigger biotic and abiotic geochemical reactions. The likelihood and severity at storage scale may however be significantly different for the following underlying reasons:

- A salt cavern has a much lower surface of contact between the aqueous solution and both rocks and gas than a porous storage, which limits the extent of possible active bacterial biofilm, in contact with the aqueous phase and the gas, and of the gas and minerals dissolution kinetics.
- The aqueous solution in a salt cavern in operation is Halite-saturated: approximately 320 g of NaCl per liter is dissolved. This causes osmotic stress in cells leading to highly reduced diversity and abundancy of the microorganisms. The likelihood that these microorganisms have entered the cavern is therefore reduced.[3]

Due to these two reasons, the risk to observe bacteria development in porous media is higher. This microbial diversity and its influence on natural gas storage was for example studied by Ranchou-Peyruse et al. (2021). They concluded that deep aquifers contain massive volumes of water harboring large and diverse microbial communities. Nevertheless, with natural gas there is no risk of production loss but rather a positive effect with BTEX biodegradation in water or negative effect with production of contaminant as H_2S.

H_2 concentration in the subsurface may stimulate the growth of H_2-oxidizing microorganisms, which will consume part of the injected hydrogen. It has been the focus of recent publications. Dopffel et al. (2021) characterized different microbial issues, giving key indicators for the processes, and giving advises for the monitoring and management of microbial activity in subsurface H_2 storage in porous media. Thaysen et al. (2021) reviewed the main control mechanisms (such as temperature, pressure, salinity, pH) of the microbiological activity and compared the optimum growth conditions to those of 42 British depleted oil and gas fields. It leads to a first estimation of the hydrogen consumption, *"negligible to small (<0.01–3.2% of the stored hydrogen)"*. This calculation of the hydrogen consumption in a storage system is presented as a minimum approach, but on the other hand the kinetic aspects at reservoir scale, which would probably require a reservoir reactive transport modelling approach are not included yet, and it is unclear whether such consumption is reached during a single cycle or not. From the conclusion of this analysis, we also note that selecting the reservoirs found to be less prone to microbiological activity directly impacts the cost: it leads to selecting high salinity and high temperature reservoirs, which are deeper and more expensive to develop. Hystories WP3 is itself conducting experiments to assess the impact of microorganism, but results have not been upscaled yet to the reservoir level.

Besides Thaysen et al. (2021), public literature is scarce regarding the estimation of microbial reaction at reservoir scale. Nevertheless, Bo et al. (2021) presented another estimation of

[3] Dopffel et al. (2021) however mention that this "does not necessarily lower the risks of microbial H2 consumption", would an appropriate microorganism enter the cavern. The analyses of the (limited) analogues in salt caverns suggest instead that the likelihood is relatively high, but the impact low.

hydrogen loss in sandstone reservoirs. Two kinetic simulations were performed using PHREEQC software. It leads to 0.72 % and 2.76 % of hydrogen loss over 30 years. The highest consumption was due to calcite dissolution of the reservoirs that was highlighted as very reactive towards hydrogen taking into account bacteria aqueous solution reactions.

Literature does however provide three analogues that are relatively relevant, from the historical experience of underground storage of hydrogen-rich Town gas (Typically containing 30 to 50% of hydrogen, along with CH_4, CO_2 and CO) in a dozen of aquifers or depleted fields:

- Heinemann et al. (2021) report a 17% decrease in hydrogen concentration over a 7-month cycle in Lobodice (Cezch Republic). Dopffel et al. (2021) mention that half the hydrogen stored in Lobodice has been consumed (without mention of the duration for it). The source article, Smigan et al., 1990 (Table 1) reports that while the injected gas had a 54% Hydrogen content, the withdrawn gas, 7 months later, has a 37% hydrogen content, i.e. a 31% loss.
- Panfilov (2010) mention that Beynes depleted field storage (France) recorded "similar phenomena" as those recorded in Lobodice. Apparently in contradiction, Heinemann et al. (2021) report that no hydrogen consumption was reported in Beynes. The operator of the site that is now a natural gas storage site, Storengy, mentions in Marcogaz, 2017 that "in Beynes, the impact was real but limited (Storengy unpublished information)."
- Marcogaz (2017) report that in Ketzin aquifer storage (Germany), "61 % of H_2 volume has been lost (8 million m3/year) […] as well as important modifications on gas composition and H_2S generation and pressure losses/temperature changes" based on DGMK Research Reports;

The two recent pilot projects of Sun.storage and HyChico also provide relatively relevant analogues:

- The final report of the Sun.Storage project (RAG, 2017) that consisted in 10 % hydrogen and natural gas injection in a small isolated depleted gas field in Lehen, Austria (6 million Nm^3 total gas), determined that 3% of the hydrogen introduced was converted to methane, based on a balance of the carbon dioxide that is injected (~0.20% of the injected natural gas) and withdrawn. However, the evolution of this injected minus produced carbon dioxide balance over time suggests a steady decrease of this consumption (fig. 91 in RAG, 2017). In the Underground Sun Conversion follow-up project, batch injections of 10% or 20 % hydrogen and 2.5% of CO_2 and natural gas were done on the same Lehen field, showing a consumption of hydrogen (RAG, 2021). CO_2 was injected purposely to enhance the methanogenesis. This project also enabled to measure that in-between the two projects, the hydrogen content in the withdrawn gas decreased from 2% in early 2017 to 1% August 2018.
- Dopffel et al. (2021) mention that a microbially triggered H_2 loss was observed in HyChico pilot, in Argentina.

The impact of biotic (essentially) and abiotic (possibly) reaction at reservoir scale is very site specific, and the above-mentioned analogues show that the range of impact on the loss of hydrogen can be large. Besides the site-specificity, these figures are difficult to extrapolate quantitatively for future storages for several reasons:

- Town gas analogues and the Sun.Storage project had co-injections CO2 (and CO in the case of Town gas) along with the hydrogen. This can support the methanogen activity in these cases, but these conditions should not be found in pure hydrogen storage (besides the case of CO_2 initially present in the native or cushion gas)
- Duration of the observation is not always known and is limited for pilots when compared to a real storage lifetime, which may not enable to observe saturation effects.
- When part of the hydrogen is not recovered in analogues, it may not necessarily be consumed, it can also be related to hydrogen mobility in the reservoir, to mixing with residual native gases, or other trapping mechanisms (dissolution, residual trapping).
- The approaches based on results of lab experiments are generally not upscaled to assess an impact at the reservoir scale, with the notable exception of Thaysen et al. (2021) which is also a very large one, based on 518 cultivated strains from the three major groups of H2-oxidizing microorganisms. Even in the latter, gaps remain notably to validate the upscaled approach with field-scale observations, and to include the kinetics of the reactions at reservoir scale.

The following table summarises the findings from these analogues in Porous Media.

Table 42: Synthesis of the likelihood and severity of hydrogen contamination in porous media from analogues, lab and modelling works

Reference	Occurrence of noticeable effect of the microbiological activity	Severity when happening	Remark
Natural gas storage	Circa. 90 %	Purity question or BTEX biodegradation in water, but no product loss	There is no dissolved hydrogen, relevance can be discussed.
Town gas storage	100%	From no observation (but contradictory with an other publication) to very significant (61% loss)	-Public information was found for only 3 of the dozen of town gas historical storages -Published information is partly contradictory on Lobodice and Beynes -Town gas includes CO and CO2, providing a constant source of carbonate. -It is not always clear whether hydrogen was consumed by microorganisms, trapped or escaped.

H_2 and Natural gas blend storage pilots	100%	Small and decreasing over time (3% in average)	During the Underground Sun.Storage project (RAG, 2017), the injected gas contained 10% H2, but also ~0.2% CO2, supporting the methanogenesis activity
Analysis and modelling of the impact up to cavern scale	N/A	"negligible to small (<0.01–3.2% of the stored hydrogen)"	Only 2 recent references, Thaysen et al. 2021 : < 0.01 – 3.2 % Bo et al. 2021 : 0.72 – 2.76 %

In a first approach and for further conceptual project economic evaluation of a typical porous media storage site, it is proposed to assume that 1.5% of the injected hydrogen is not recovered, acknowledging that this is a hypothetical figure at this stage, and that analogues suggest that the range is large. It is half the results from Sun.Storage estimated consumption (but this case also had a traces of CO_2 injected), in the middle of the range given by Thaysen et al. (2021) and Bo et al. (2021). It is much lower than the historical experience in Ketzin, Lobodice and Beynes, but these have contradictory published information, and are a significantly different case due to the co-injection of CO and CO_2.

Table 43: Hydrogen losses in Porous media storage

$\boldsymbol{H_2Loss_{Porous}}$	$\boldsymbol{H_2Loss_{Porous}} = \left(\frac{Injected\ working\ gas - Withdrawn\ gas}{Injected\ working\ gas}\right) = 1.5\%$

This consumption of hydrogen generates by-products, possibly gases that will have to be separated when withdrawing. In addition to this, porous media storage may possibly contain residual or native gases. These are reasons for considering a gas treatment unit for aquifer and depleted field storages, and none for salt caverns.

7.5. Insights on storage design lifetime and storage capacity to deliverability ratio

For cost estimate purpose, it is reasonable to assume the following lifetimes:

- 30 years for injection and withdrawal facilities.
- 50 years for the “storage” part of the asset, such as a salt cavern.

Among the site characteristics, the storage capacity to storage deliverability ratio is a design choice for each project, even if limited by technical constraints. For this ratio, the following table presents both:

- The figures that are derived from the Conceptual design (Deliverable D7.1-1). The costs derived in the present D7.2-1 are based on these ratios.
- The minimum reasonable technical value for this ratio. We recommend using this value when looking at the minimum of the volume to withdrawal ratio, for instance in Energy system modelling of WP5. Since the unit costs have not been built on this basis, the costs are more uncertain, and using the range of the costs (as given e.g. in the Executive Summary Table 1) is recommended in as a sensitivity or uncertainty analysis.

Table 44: Working gas to deliverability ratios

Technology	Conceptual design D7.1-1 (basis for D7.2-1 costs estimate)			Minimum reasonable technical volume to withdrawal flowrate ratio	
	Working Gas	Deliverability (Withdrawal rate)	Volume to Withdrawal flowrate ratio		
	[10^6 Sm^3]	[10^6 Sm^3/d]	[GWh/(GWh/h)] or [Sm^3/(Sm^3/h)] or hours	[GWh/(GWh/h)] or [Sm^3/(Sm^3/h)] or hours	days
Salt caverns	31.25 (per cavern)	2.79 (per cavern)	269	264 *	11
Porous media	550	8.25	1600**	828 **	34.5

* This derived from the conceptual design technical hypotheses: 110 bar of pressure operation range in the cavern, and a maximum pressure decrease rate of 10 bar/day, leading a withdrawal duration at peak rate of 11 days (264 hours). This figure of 11 days can be considered as a minimum reasonable volume to withdrawal ratio for salt caverns, even though it could be challenged on a site-specific basis: the operation range depends on the cavern depth, and there are some caverns using less stringent ratios, such as 30 bar/d as a limit.

**: For porous media, the minimum ratio is highly dependent on the site-specific geological settings. The values are therefore based on a statistical analysis of the existing natural gas storage industry in Europe (Figure 10 and Table 9 of D7.1-1). The D7.1-1 case considered the median case, leading to a median volume to withdrawal ratio of 24h/1.5% = 1600 hours. The minimum reasonable volume to withdrawal ratio is assumed to be the last decile, 24h/2.9% = 828 hours. Lower values are possible, but rare, since 90% of the natural gas porous media storage cases are above this value.

These results can be compared to the current situation in natural gas storage in EU-27 + UK. The analysis of the data published by Gas Infrastructure Europe leads to a working gas volume to deliverability ratios of 767 $Sm^3/(Sm^3/h)$ for salt caverns and 1555 $Sm^3/(Sm^3/h)$ for porous media.

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