IFE

Research for a better future

28.10. 2020

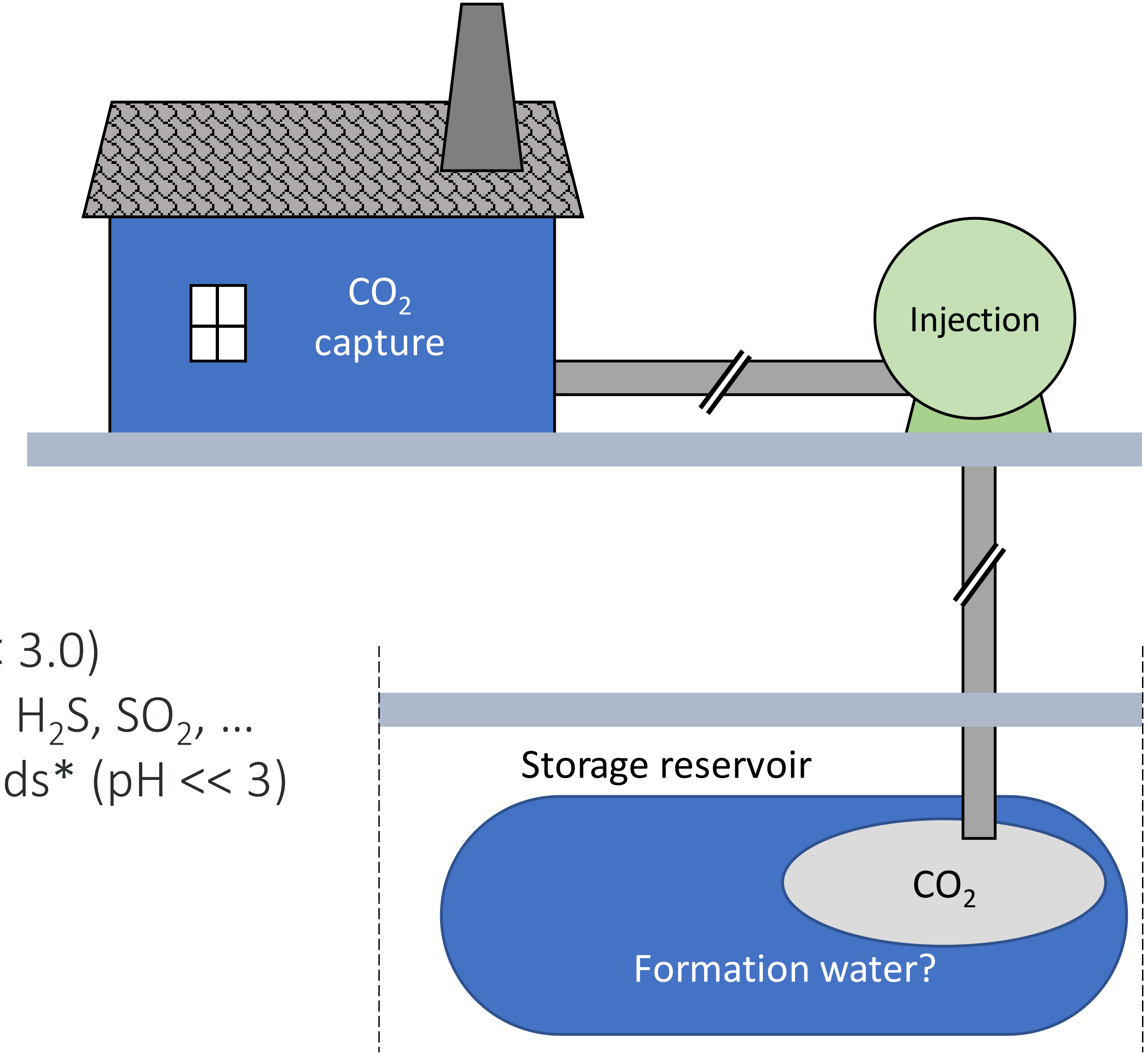
Presentation held at the Virtual SPE CCUS Conference 2020

Well material selection for CO_2 storage

Gaute Svenningsen
Institute for Energy Technology (IFE)
NO-2027 Kjeller
Norway

Introduction

- Oil and gas wells have always been exposed to CO_2, but at “moderate” levels, e.g. ~ 0.1 – 10 bar CO_2.
- The general design codes still apply to CO_2 injection wells, but…
- Injection wells may have>> 150 bar CO_2
  - Low pH, particularly in condensed water(< 3.0)
  - Constant supply of impurities like O_2, NO_2, H_2S, SO_2, …
  - Impurities may react and create strong acids* (pH << 3)
- Long-life of injection well perspective
- No leak after injection has stopped.



* Morland, Tjelta, Norby, Svenningsen, International Journal of Greenhouse Gas Control, 87, (2019) pp. 246-255.

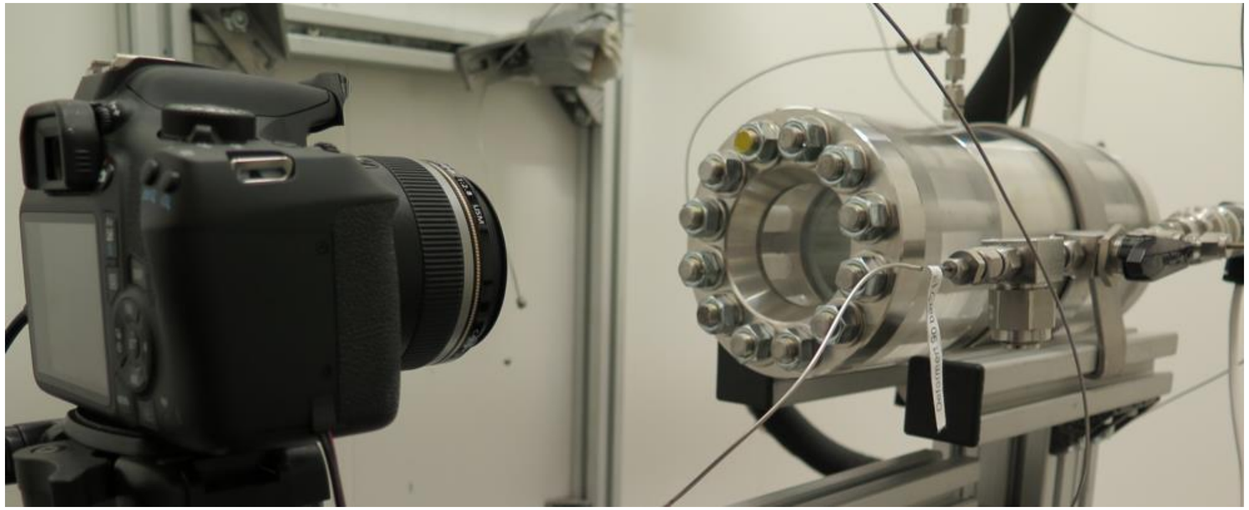
Verifying the material performance in the lab

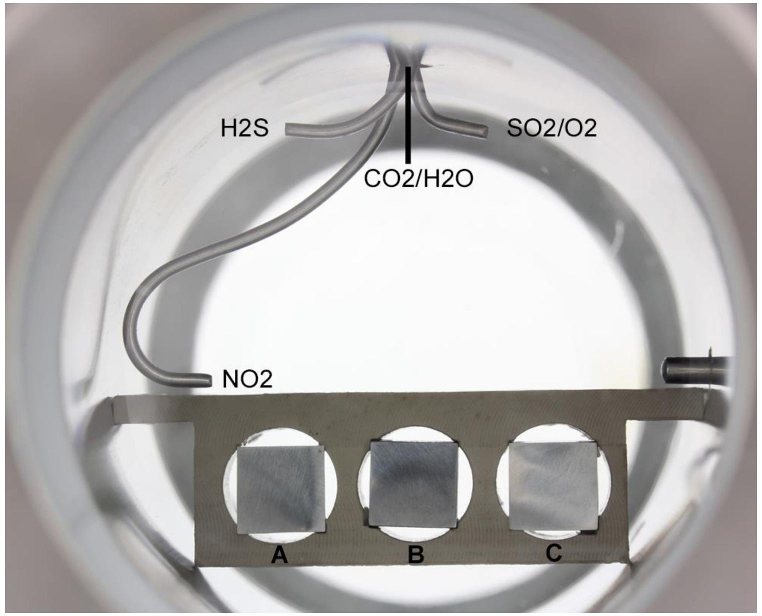
Use realistic test conditions (along the CCS chain)

- **A: CO_2 transport in pipelines**
  - Low to intermediate temperature (0 – 50°C)
  - High pressure >70 bar
  - No water: Carbon steel can be used
- **B: CO_2 transport with ships**
  - Low temperature (-40 - +10°C, low pressure)
  - No water: Carbon steel can be used
- **C: Well / down hole (CO_2 injection)**
  - Hight pressure and temperature
  - Water is present (formation water or condensed water)
  - Use CRA (Corr. rate of carbon steel >> 10mm/y)

Impurities must be included in the testing

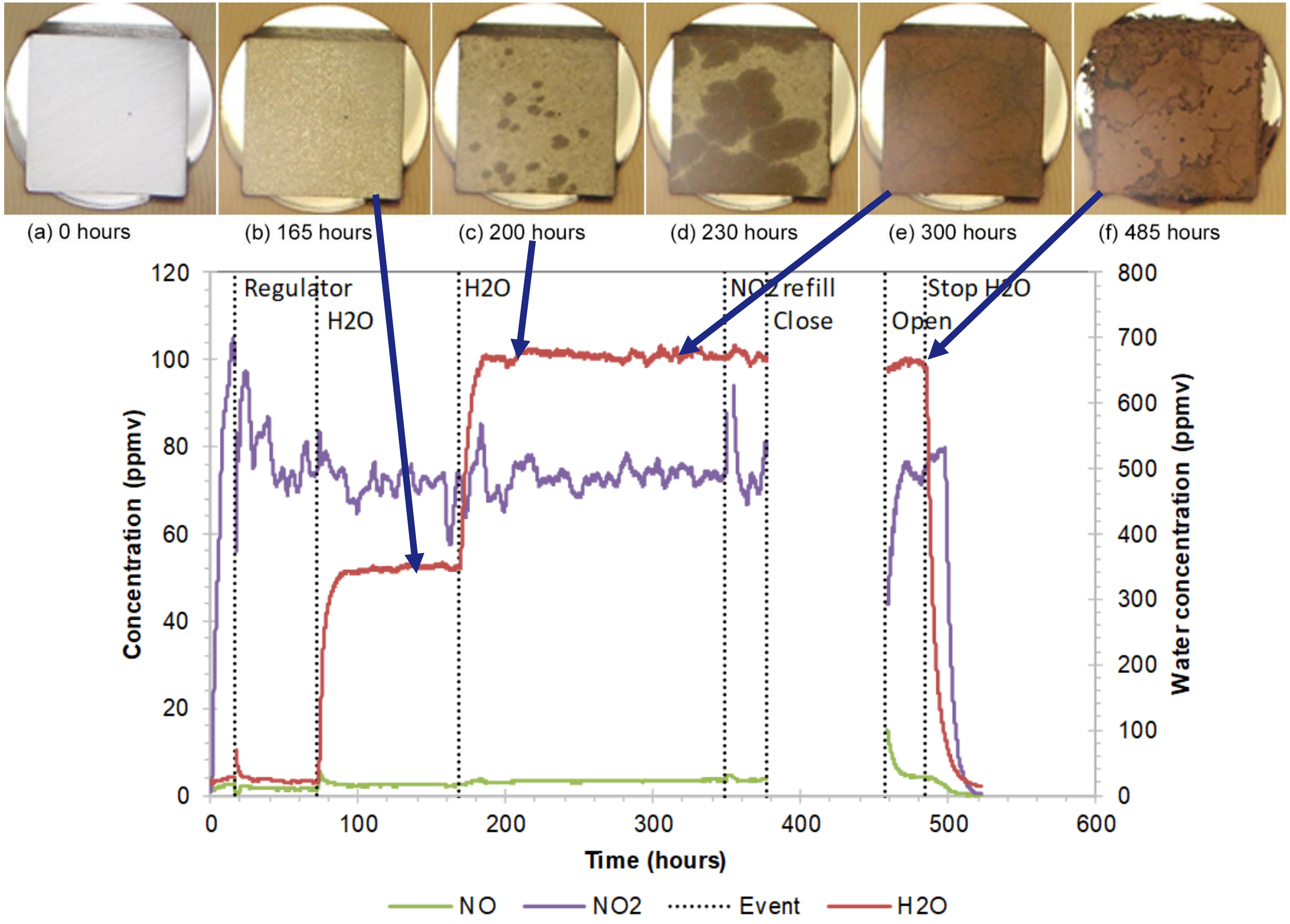
- Origin from flue gases and capturing processes
- Continuous feed
- Low concentration, typically 10 – 100 ppm-mol level





CO_2 pipeline test: CO_2 with NO_2 and H_2O*

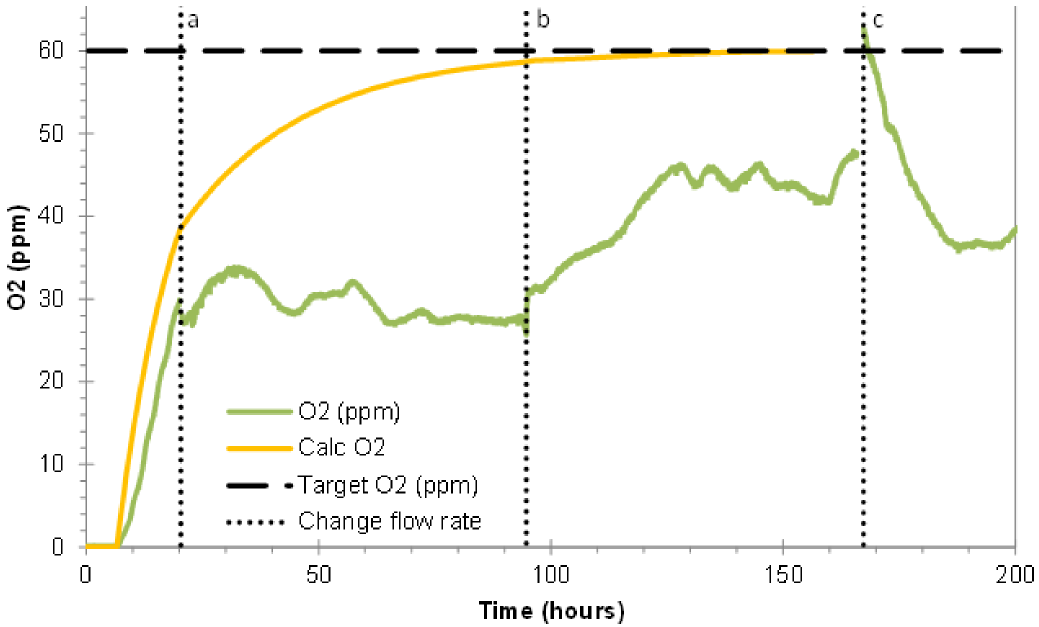
- Carbon steel
- Dense phase CO_2
- 100 bar / 25°C
- 72 ppm-mol NO_2
- Stepwise increase of H_2O:
  24 => 350 => 675 ppm-mol
  (the water was fully dissolved in the CO_2 bulk phase, no liquid water present)

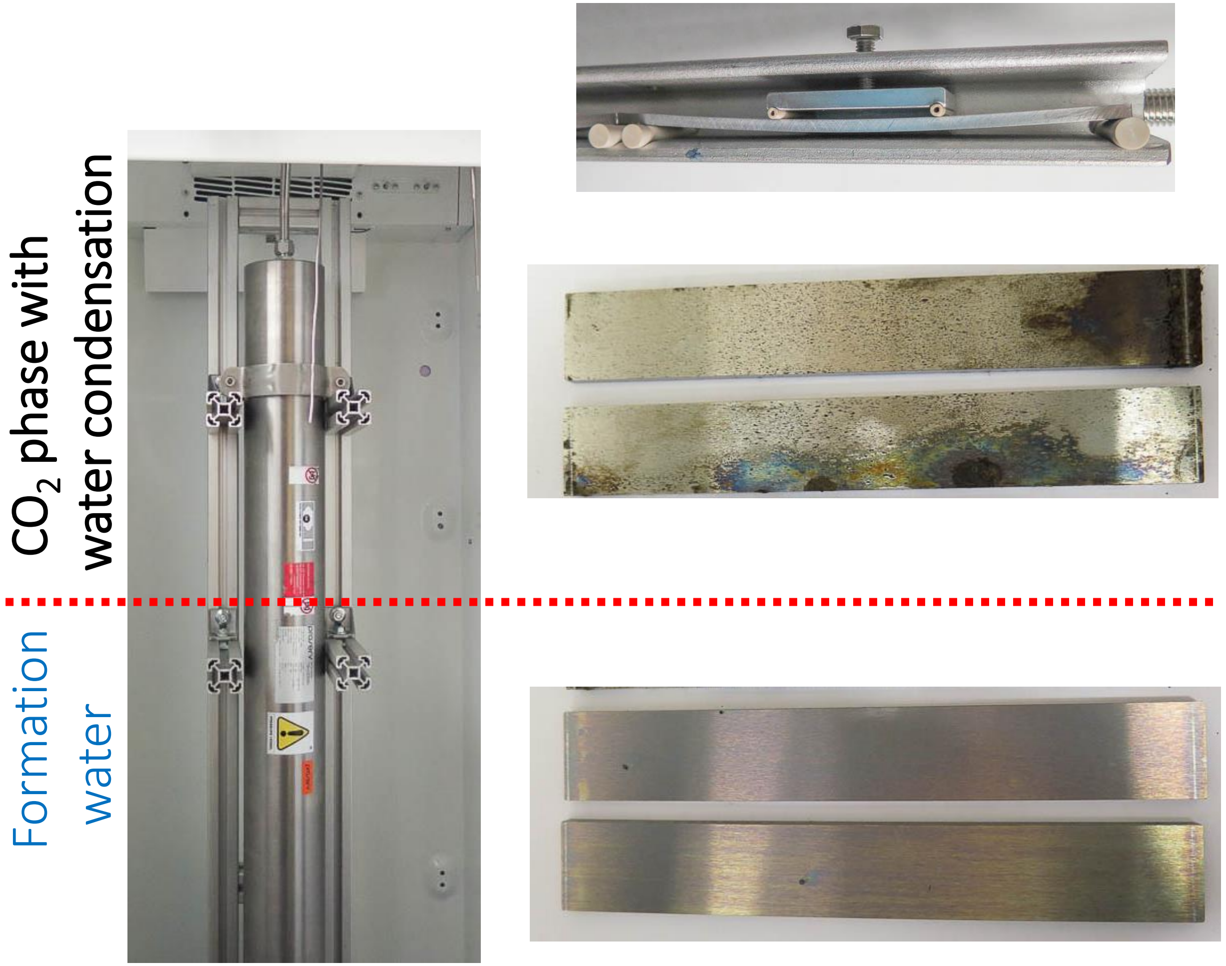


*Morland, Norby, Tjelta, Svenningsen, *CORROSION*, 75, 11 (2019) pp. 1327-1338.

Down hole test: SCC test of 13Cr with O_2*

- 13Cr-L80 stainless steel
- 4 point bend for SCC testing
- 190 bar / 85°C
- Supercritical CO_2 and formation water
- Continuous injection of CO_2 with 60 ppm-mol O_2
- Localised corrosion, but no SCC observed



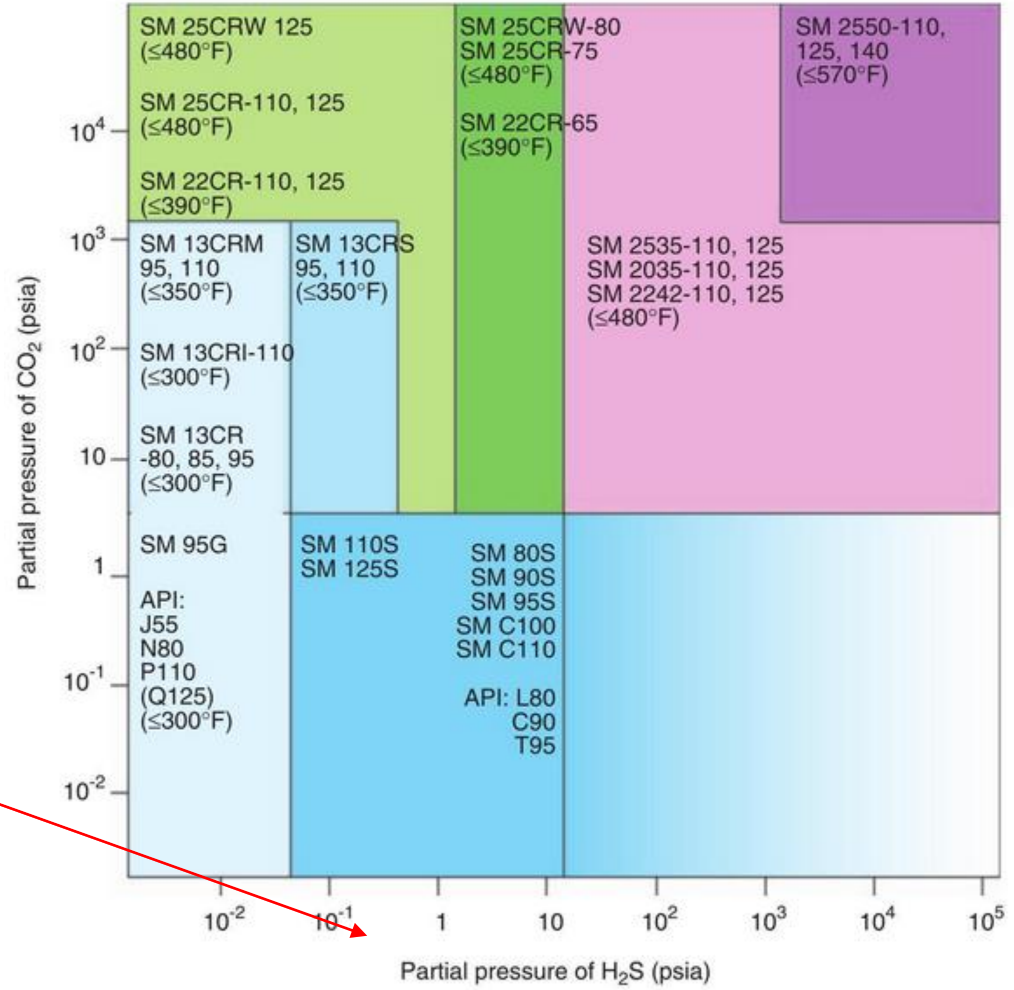


*Svenningsen, Morland, Dugstad, Thomas, *Energy Procedia*, 114, (2017) pp. 6778-6799.

Topics to be studied further

- 13Cr cs S13Cr vs 22Cr vs 25Cr vs. nickel alloys
- “Evaporation” of formation water ⇒ concentrated salt brine (locally) ⇒ Increased risk of SCC?
- Condensed water ⇒ pH << 3?
- Localised corrosion?
- How to assess H_2S partial pressure limit for sulphide stress cracking in dense phase CO_2 (when H_2S is not present as a gas)?
- Effect of high CO_2 pressure (fugacity) on cement?

First-pass material selection chart, adopted from Sumitomo Metals *



* Bellarby, Chap. 8 Materials selection, in: Well completion design (Amsterdam: Elsevier, 2009) pp. 433-472.

Thank you for your attention!

www.ife.no facebook.com/energiteknikk/ @energiteknikk