

APPENDIX EA – SOLE-2 SAMPLE ANALYSIS: SUMMARY OF H₂S TESTS & RESULTS

1 RECOMMENDATION

A most-likely Sole Field H₂S concentration of 1,050 ppm has been determined following detailed compositional analysis of fluid samples recovered from the Sole-2 well. A maximum design limit of 1,500 ppm is proposed, based on the stated accuracy of measurement techniques and incorporating a safety margin.

2 SUMMARY OF SOLE-2 FLUID SAMPLING OPERATIONS

Various fluid samples were collected for analysis during logging and testing of the Sole-2 appraisal well. Some downhole samples were obtained during logging (17th July) and were analysed on-site whilst others were retained in H₂S-resistant sample chambers, to minimise adsorption into the steel chamber lining, and transferred to an onshore laboratory for analysis. Separator gas samples were also recovered during drill-stem testing (18th August) for onshore analysis. In addition, on-site measurements of H₂S were made from the choke manifold using conventional test equipment. The following valid data constitutes the range of H₂S measurements obtained from all analyses:

Measurement	Technique	Time (inflow to analysis)	H ₂ S ppm
MDT 1-gall chamber (uncoated) – sample 0.02	Kitigawa	6 hours	* 625 ppm
MDT 1-gall chamber (uncoated) – sample 0.01	Kitigawa	12 hours	* 400 ppm
MDT 250cc SPMC (coated) – sample 1.03	Draeger	14 days	* 550 ppm
MDT 250cc SPMC (coated) – sample 1.03	Kitigawa	14 days	* 500 ppm
MDT 250cc SPMC (coated) – sample 1.03	Tutweiler	12 days	* 430 ppm
MDT 250cc SPMC (coated) – sample 1.03 (repeat)	Tutweiler	9 days	* 415 ppm
MDT 250cc SPMC (coated) – sample 1.04	Draeger	14 days	* 615 ppm
MDT 250cc SPMC (coated) – sample 1.04	Tutweiler	14 days	* 525 ppm
DST : on-site separator samples	Draeger **	10 mins	~ 1,000 ppm
DST : separator samples (uncoated) – 2.02	ASTM-D2725 ***	24 days	580 ppm
DST : separator samples (uncoated) – 2.01	GC-FPD	38 days	1,650 ppm
DST : separator samples (uncoated) – 2.02	GC-FPD	38 days	1,500 ppm
DST : separator samples (uncoated) – 2.03	GC-FPD	38 days	1,470 ppm
DST : separator samples (uncoated) – 2.04	GC-FPD	38 days	1,440 ppm
DST : separator samples (uncoated) – 2.05	GC-FPD	38 days	1,390 ppm
DST : separator samples (uncoated) – 2.06	GC-FPD	38 days	1,440 ppm
DST : separator samples (uncoated) – 2.02	GC-FPD	46 days	1,340 ppm
Existing 100ppm GC-MS gas standard #	Draeger	-	100 ppm
DST : separator samples (uncoated) – 2.01	Draeger	70 days	800 ppm
DST : separator samples (uncoated) – 2.02	Draeger	70 days	1,000 ppm

DST : separator samples (uncoated) – 2.03	Draeger	70 days	900 ppm
DST : separator samples (uncoated) – 2.04	Draeger	70 days	900 ppm
DST : separator samples (uncoated) – 2.05	Draeger	70 days	800 ppm
DST : separator samples (uncoated) – 2.06	Draeger	70 days	850 ppm
DST : separator samples (uncoated) – 2.02	GC-FPD	77 days	1,020 ppm
DST : separator samples (uncoated) – 2.02	GC-FPD	105 days	1,000 ppm
DST : separator samples (uncoated) – 2.01 ^{##}	GC-FPD	124 days	1,050 ppm
DST : separator samples (uncoated) – 2.02 ^{##}	GC-FPD	124 days	970 ppm
DST : separator samples (uncoated) – 2.03 ^{##}	GC-FPD	124 days	920 ppm
DST : separator samples (uncoated) – 2.04 ^{##}	GC-FPD	124 days	910 ppm
DST : separator samples (uncoated) – 2.05 ^{##}	GC-FPD	124 days	890 ppm
DST : separator samples (uncoated) – 2.06 ^{##}	GC-FPD	124 days	910 ppm

- * some H₂S also contained in associated filtrate as sulphides
- ** 15 measurements between 980-1,200ppm by 3 different operators (all H₂S-experienced)
- *** analytical technique significantly modified for high H₂S concentration
- # calibration of standard conducted on same day as Draeger analysis of 5 separator samples
- ## analysis conducted using high-ppm gas standard

It should be noted that several of the initial laboratory analyses were subject to scaling errors due to the small size of the samples recovered.

Whilst the GC-FPD is a highly accurate measurement technique, it is reliant on the validity of a calibration gas standard. The gas standard used was 100ppm H₂S (manufactured June 2002, valid for 2 years and NATA/ISO-certified) and therefore some dilution of the samples was required due to the high Sole gas H₂S concentration. The dilution procedures employed during early GC testing (batch of samples analysed after 38 days) were questionable and, following discussion with the OMV Vienna laboratory, Geotech improved their procedures.

New gas standards were also sourced in December 2002 (100ppm, 1,000ppm & 2,000ppm) to confirm whether the initial GC-FPD measurements were valid. All samples were reanalysed by GC-FPD using the high-ppm gas standards. Analysis of all samples (~1,000ppm) suggested that the early measurements (~1,500ppm) may have been invalid, given the relatively small amount of adsorption expected with high-ppm gas samples (supported by OMV Vienna laboratory).

Final measurements of 1,000-1,200ppm (after 124 days) agreed closely with Draeger measurements made on-site during well testing. Based on the stated accuracy of the Draeger tube measurement and the excellent repeatability of all samples, as well as the on-site nature of the measurement (no sample chamber adsorption issues), a wellhead gas concentration range of 800-1,400ppm (90% confidence interval) is proposed. Assuming some minor H₂S adsorption upstream of the sampling point during drill-stem testing, a maximum in-situ reservoir concentration of 1,500ppm is recommended for design work.

In addition to determination of H₂S in separator samples, Geotech also conducted analysis for other sulphur-based compounds. Incorporation of this data yields the following range of initial Sole gas composition:

Compound	Minimum (ppm)	Most-Likely (ppm)	Maximum (ppm)
Hydrogen sulphide	800	1,050	1,500
Carbonyl sulphide	0	< 5	5
Methyl mercaptan	0	< 5	5
Ethanethiol	1	2	3
Methyl sulphide	0	1	1
2-propanethiol	0	1	1
2-methyl 2-propanethiol	0	1	1

3 RESERVOIR FLUID SAMPLES: WIRELINE MDT

Six downhole gas samples were obtained using the wireline-conveyed MDT tool. Four were housed in ceramic-coated H₂S -resistant 250cc sample chambers to minimise adsorption of H₂S into the steel lining. The ceramic coating was recommended by Oilphase as being superior to conventional teflon-coating in terms of retention of H₂S. The remaining two samples were housed in 1-gallon segregated sample chambers with no protective lining to the steel walls of the chamber. The order and depth of these samples was as follows :

Sample #	Sample Date/Time	Depth	Sample Chamber Type
Sample 0.01	17 July 2002 15:40	810.0 mMDKB	1-gallon MRSC dump chamber
Sample 1.01	17 July 2002 15:45	810.0 mMDKB	250cc SPMC (ceramic-coated)
Sample 1.02	17 July 2002 15:47	810.0 mMDKB	250cc SPMC (ceramic-coated)
Sample 0.02	17 July 2002 21:20	778.0 mMDKB	1-gallon MRSC dump chamber
Sample 1.03	17 July 2002 21:29	778.0 mMDKB	250cc SPMC (ceramic-coated)
Sample 1.04	17 July 2002 21:31	778.0 mMDKB	250cc SPMC (ceramic-coated)

Once the MDT toolstring had been recovered at surface, samples were drawn off the two MRSC dump chambers for immediate on-site analysis using Kitigawa tubes (for H₂S) and the rig GC (for other components). H₂S measurements of 400ppm and 625 ppm were reported for samples 0.01 & 0.02 respectively.

The difference between the two measurements was believed to be due to :

- 6-hour lag between two samples – additional H₂S adsorption during that time.
- potential air contamination during Kitigawa sampling procedure.

The contents of the four SPMC's were transferred under pressure into ceramic-lined NSB transit bottles and transported to Core Lab in Perth for analysis. The following results were obtained

- 1.01 drained 2 ml grey filtrate (sulphide), flashed gas yielded 0 ppm H₂S by Tutweiler analysis (small volume sampled).
- 1.02 drained 8 ml black filtrate (sulphide 2 mg/L measured by Geotech), flashed gas yielded < 100 ppm by GC. Tutweiler analysis failed (small volume sampled).
- 1.03 drained 2 ml black filtrate (sulphide 19 mg/L measured by Geotech), flashed gas yielded 550 ppm (Core Lab Draeger), 500 ppm (Oilphase Kitigawa), 415 ppm (Tutweiler).
- 1.04 drained filtrate, 16cc evolved gas yielded 615 ppm (Draeger), 525 ppm (Tutweiler).

The H₂S measurements from samples 1.03 & 1.04 were comparable to the on-site analysis of the 1-gallon dump chambers conducted shortly after samples were acquired. This suggested that ceramic coating of the SPMC/NSB bottles was successful in retaining the majority of sampled H₂S.

The Tutweiler test (UOP 9-59) has a lower limit of 80 ppm and “repeatability should be better than 75 ppm otherwise results are considered to be suspect.” [Core Lab]

4 SEPARATOR GAS SAMPLES: DRILL-STEM TEST

Six 20-litre gas samples were recovered from the test separator during testing operations (see setup photos). Refer to Attachment EA2 for summarised procedures used. It was initially believed that all sample chambers were teflon-lined, although Expro later advised that they were all unlined, i.e. standard aluminium alloy (compliant to NACE MR 0175). Slow transit between rig and laboratory resulted in a delay of several weeks between sample acquisition and analysis. Following their arrival in Perth, the samples were directed to Geotech, who conducted H₂S determination by wet chemistry (ASTM-D-2725 methylene blue test) on sample 2.02 to gauge the level of H₂S absorption that had occurred. Analysis yielded an H₂S content of 580 ppm. Quick-look analyses on the remaining five separator samples using the same technique indicated broadly similar levels of H₂S.

All six samples were then analysed for H₂S and other sulphur compounds using a GC-FPD technique, which is the most accurate technique available to determine H₂S and has a detection limit of 0.1 – 4,000 ppm (based on 1cc sample size) [Core Lab].

5 DISCUSSION

Wireline MDT samples

Initial sample analysis results indicated a significant reduction in measured H₂S between wellsite test measurements and ‘preserved’ MDT sample analysis. This was believed to be due to one/both of the following:

- a) MDT samples were never truly representative of reservoir fluid due to dissolution of H₂S into filtrate as gas flowed into the MDT tool probe.
- b) Adsorption of H₂S into lining of SPMC chamber walls in transit to onshore laboratory.

Given that the analysis of samples 0.01 & 0.02 yielded measurements of H₂S similar to laboratory analysis of the preserved samples, it followed that conclusion a) was the major factor contributing to the difference. It was therefore concluded that the most accurate determination of H₂S would be achieved from samples obtained during well testing, where clean up has been completed prior to the commencement of sampling.

Separator DST Samples

Whilst Draeger analysis of surface samples appeared to have delivered the most representative results (1,000-1,200 ppm), subsequent analysis of ‘preserved’ separator samples by GC-FPD has indicated H₂S levels as high as 1,650 ppm (sample retained in unlined sample chamber for 38 days prior to analysis). Good repeatability of measurements was apparent from all six samples. A rigorous sample analysis programme was put together based on these results in an effort to reduce the uncertainty in apparent H₂S levels.

Sample Analysis Accuracy

Based on discussion with relevant companies (Geotech, Petrotech, Oilphase & Core Lab), the following specifications were supplied for each measurement technique:

Technique	Range	Accuracy	Source
• Draeger tube	100 – 2,000 ppm	+/- 10% full scale	Petrotech
• Kitigawa tube	50 – 1,000 ppm	+/- 10% full scale	"
• ASTM D-2725	0.1 – 16 ppm	+/- 10%	ASTM
• ASTM D-2385	0.1 – 7 ppm	+/- 10%	ASTM
• UOP 9-59 (Tutweiler)	> 80 ppm	+/- 10%	Core Lab
• GC-MS/FPD	0.1 – 4,000 ppm	+/- 4%	Geotech

Based on these figures, using GC-FPD for sulphur detection is deemed to be the most accurate detection method available (Geotech currently have the only facility in WA). However, GC measurements are highly dependent on the quality of the calibration gas (100ppm H₂S initially installed in Geotech's equipment), which is contained in an 'H₂S - inert' cylinder within the apparatus. If the level of H₂S within the calibration decreases for any reason (eg. adsorption into 'inert' cylinder metal), measurements of H₂S on subsequent samples will appear higher than actual.

A dilution procedure was initially required due to the high Sole gas H₂S concentration – this is also a potential source of error, particularly based on the 1cc sample size. Recent calibration of the 100ppm standard (using Draeger tube & 1,000/ 2,000-ppm gas standards) indicated that the standard concentration was accurate, suggesting that dilution was likely to be the source of any measurement error. For this reason, a further calibration test on the GC-FPD was conducted with a new standard which had an H₂S concentration that was more representative of the Sole-2 gas (1,000ppm & 2,000ppm H₂S standards were sourced).

Wet chemistry methods (ASTM D2725 & 2385), though used and reported by the laboratory in question, were considered to be inappropriate for Sole sample analysis, based on the high H₂S concentration. Inspection of the ASTM methods revealed a maximum concentration of 16 ppm for the analysis to be valid, clearly inadequate for the Sole gas samples.

Given the stated accuracy of Draeger tube analysis, it is concluded that the maximum possible H₂S content measured during testing was 1,400 ppm (1,200 ppm measured plus 200 ppm maximum error). This analysis was conducted on 'fresh' samples and therefore least susceptible to errors associated with H₂S adsorption. An unknown amount of adsorption would also have occurred into the well tubing (L80 specification) and the test separator and associated surface pipework upstream of the Draeger sample point. Figures quoted are therefore referenced to the wellhead. Given the potential for upstream adsorption, a maximum H₂S concentration of 1,500 ppm at the reservoir is therefore considered accurate, based on available data.

6 CONCLUSIONS

- Invest in good-quality well test sampling equipment & methodology.
- Plan ahead to ensure correct sampling equipment/coatings are available.
- Different organisations show very different coating performance (see Attachment EA1).
- Consider downhole sampling technology for future drill-stem/production testing.
- Consider on-site analysis for future sampling operations of a critical nature.
- MDT sampling is not considered worthwhile for representative H₂S determination.
- ASTM analysis techniques are not valid for H₂S above 20ppm.
- Wet-chemistry analysis requires substantial modification for high- H₂S samples.
- GC-FPD provides most accurate analysis for H₂S, but is sensitive to calibration & sample dilution.
- Draeger analysis, when applied correctly, should provide +/- 10% (full scale) accuracy.
- Draeger measurements on Sole-2 are the only available analyses on ‘fresh’ samples.
- **Most-likely Sole H₂S – 1,050 ppm, Maximum Sole H₂S – 1,500 ppm.**

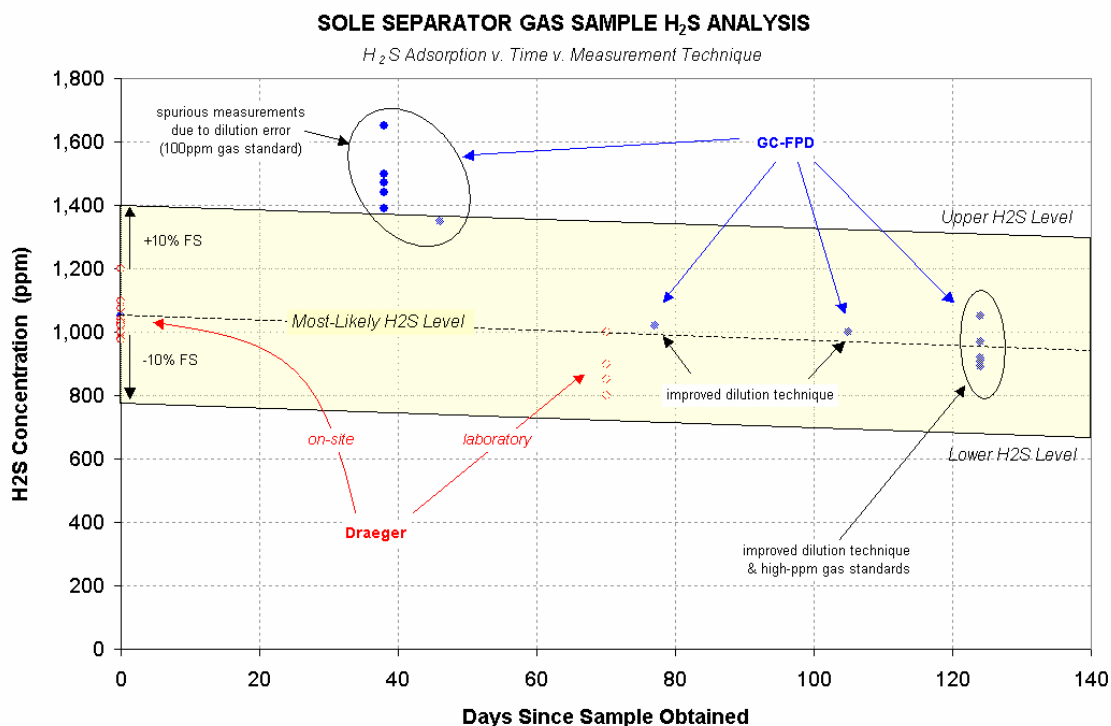
7 SEQUENCE OF EVENTS & RESULTS

	Start	End	Done
1. repeat ASTM D-2725 on sample 2.02 for consistency check	7 th Oct		
2. Geotech to discuss gas standards (GS) & detectors with OMV-Vienna	7 th Oct		✓
3. take 2 time-lapse samples from 2.02 to determine adsorption rate			✓
• first sample analysis made (+38 days) - 1,500ppm H ₂ S	26 th Sep		✓
• first time-lapse sample analysed (+46 days) - 1,350ppm H ₂ S	4 th Oct		✓
• second time-lapse sample to be analysed (+77 days) - 1,020ppm H ₂ S	3 rd Nov		✓
• third time-lapse sample to be analysed (+105 days) - 1,000ppm H ₂ S	2 nd Dec		✓
• fourth time-lapse sample to be analysed (+124 days) - 970ppm H ₂ S	18 th Dec		✓
4. consult OMV-AG on test results & available field data	24 th Oct	1 st Nov	✓
5. test old 100ppm standard (by Draeger) - 100ppm H ₂ S	28 th Oct	28 th Oct	✓
6. retest all 6 separator samples (by Draeger) - 800-1,000ppm H ₂ S	28 th Oct	28 th Oct	✓
7. test old 100ppm GS against new 100ppm GS (by GC-MS) - 100ppm H ₂ S	27 th Nov	30 th Nov	✓
8. test all samples using 2,000ppm GS (by GC-MS) - 890-1,050ppm H ₂ S	18 th Dec	18 th Dec	✓
9. conduct calibration of 1,000ppm, 2,000ppm standards (by Draeger)	10 th Jan	10 th Jan	✓
10. dose 2,000ppm- H ₂ S gas to new chamber and remeasure time-lapse [#]	N/A	N/A	

[#] item 10 not conducted due to conclusive nature of previous results.

Figure EA1 shows the various H₂S measurements made for all samples.

Figure EA1 Sole Separator Gas Sample H₂S Analysis



Attachment EA1 includes data on adsorption rate tests published by the Oilphase (Schlumberger) and Expro companies.

Attachment EA2 summarises the procedures used during :

- a) routine Draeger sampling of the test separator, and
- b) acquisition of 20-litre separator gas samples.

Attachment EA3 includes relevant reservoir/well data for the Sole Field.

Attachment EA1 - H₂S Adsorption Rates in Sample Chambers

Figure EA2 H₂S Adsorption Rates in Sample Chambers: Ceramic v No Coating (Oilphase)

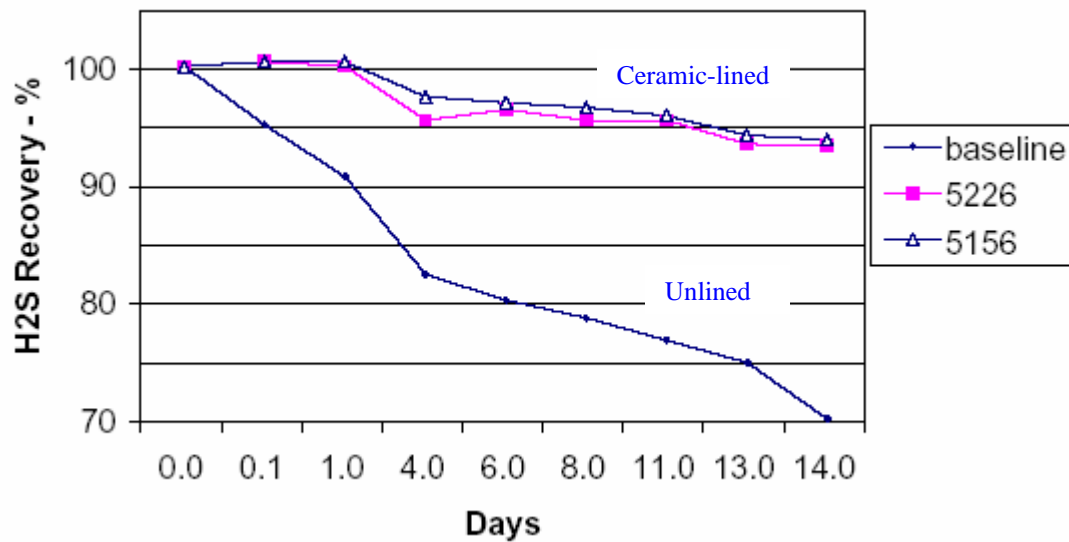


Figure EA3 H₂S Adsorption Rates in Sample Chambers: Teflon v No Coating (Oilphase)

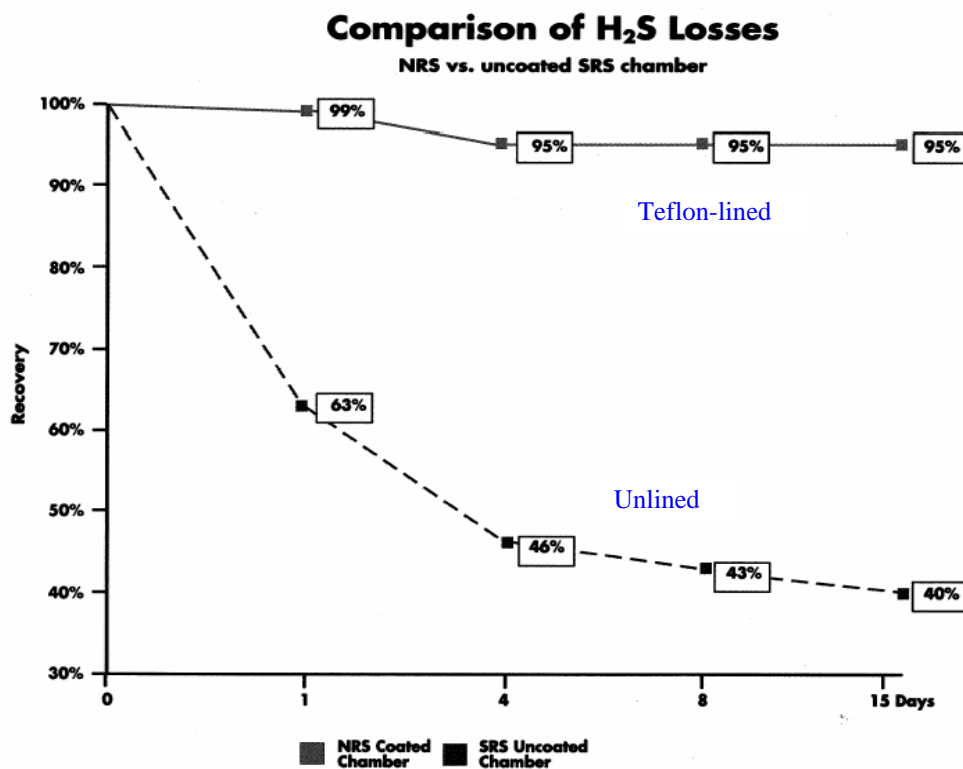
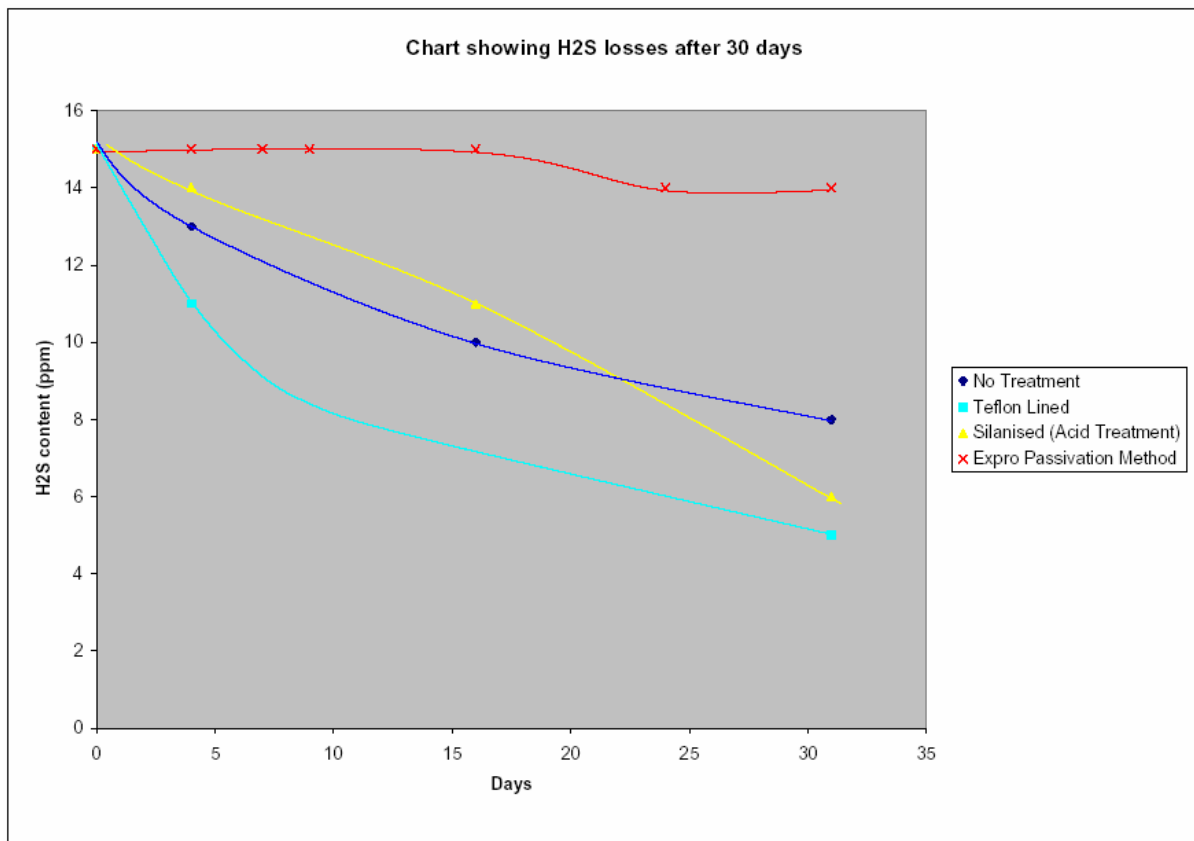


Figure EA4 H_2S Adsorption Rates in Sample Chambers: Teflon v No Coating (Expro)



Attachment EA2 - Summarised Sampling Procedures & Setup

1. Routine Draeger H₂S measurements (Figure EA5)
 - a) open valve 'D'.
 - b) flush stainless-steel sample line with separator gas for one minute.
 - c) flush solvent-resistant plastic sampling bottle.
 - d) break end off Draeger tube & insert into pump.
 - e) insert tube into sample point.
 - f) perform single complete pump stroke.
 - g) close valve 'D'.
 - h) measure H₂S level from length of discoloured material.

2. 20-litre separator samples (Figure EA6)
 - a) evacuate sample chambers on-site prior to sampling operations.
 - b) well allowed to flow for 8 hours prior to commencing sampling.
 - c) connect rubber-insulated stainless-steel sample line to sample bottle (closed).
 - d) open sample bottle valve 'A'.
 - e) open valve 'B' to flush air from sample line.
 - f) flush sample line with separator gas for one minute.
 - g) close sample bottle valve 'A'.
 - h) open sample bottle valve 'C' to fill sample chamber.
 - i) close sample bottle valve 'C' once constant-rate fill procedure completed.

Figure EA5 Sample Procedure for Draeger H₂S Measurements

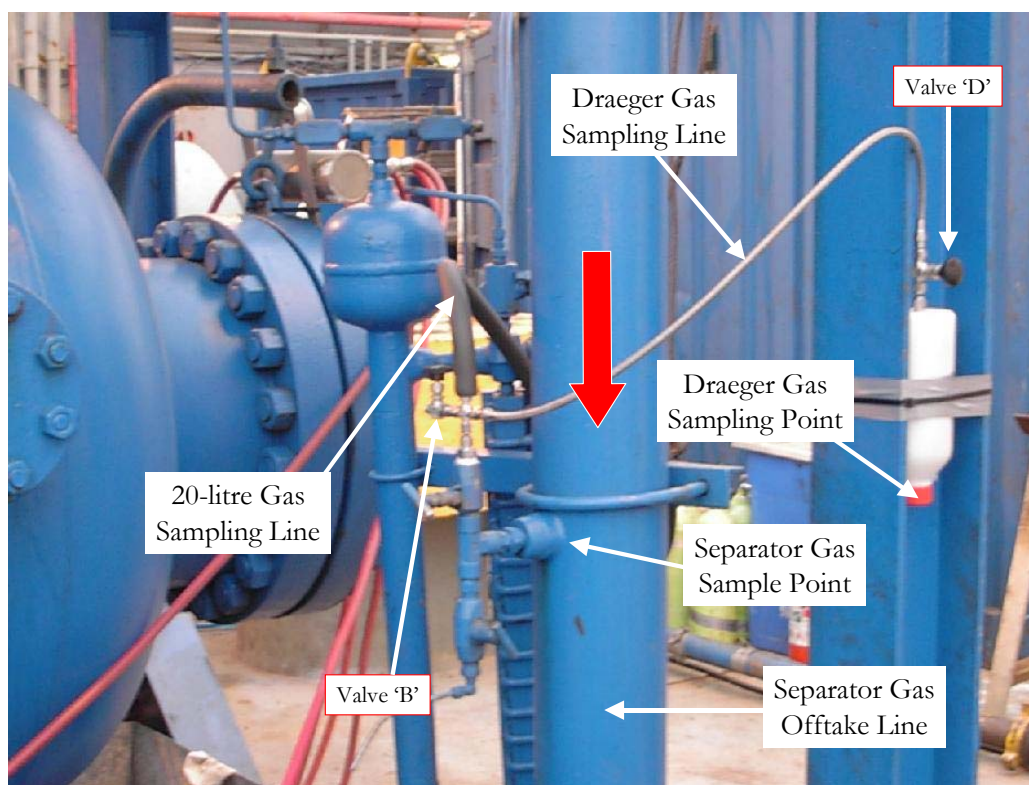
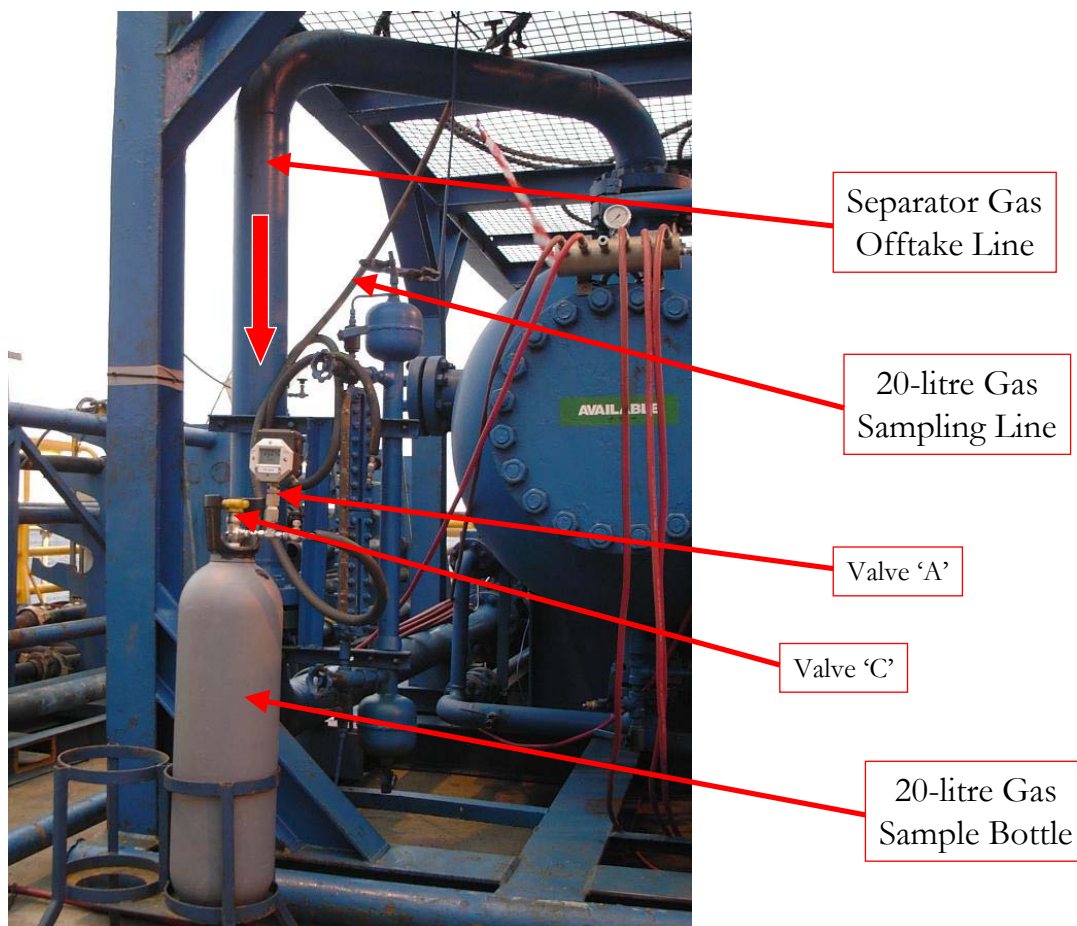


Figure EA6 Sample Procedure for 20-litre Separator Samples



Attachment EA3 - Sole Field Reservoir / Well DataGeneral

Reservoir Depth	816.5 mTVDss (Gas-Water Contact)
Water Depth	125 m
Reservoir Pressure	1,180 psia @ GWC
Reservoir Temperature	43 °C @ GWC

Sole-2 Drill-Stem Test

Tubing Size/Spec	3.5" 12.95 lb/ft L80 PH6
Well Flowrate (during sampling)	12 - 20 MMscf/d
Separator Pressure (during sampling)	310 - 330 psia
Separator Temperature (during sampling)	0 - 10 °C