Surface and Subsurface Sulphur Management and Recovery using DSR

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1 ABSTRACT

Total and CrystaTech have jointly developed a regenerable solvent based process to prevent and manage sulphur deposition during production in natural gas well bores or in the surface facilities. While producing gas from certain formations, free sulphur, if present in the reservoir fluid, may appear as a liquid or a solid phase in the well or in the surface facilities. Solid sulphur deposits on the well tubing cause gas production to diminish and ultimately stop, resulting in important production time losses and increased operating expenditures. In addition, if not removed from the process gas stream beforehand, the elemental sulphur can also have a detrimental effect on the downstream treating units.

Most existing technologies require injection of non-regenerable solvents on a batch or continuous basis. For large sour gas fields, the required amounts of solvent may not be practical due to the large volumes.

The Downhole Sulphur Recovery (DSR) technology is a regenerable solvent based process that was originally developed to mitigate large sulphur deposits in wells. The solvent dissolves the sulphur down hole and the sulphur rich solvent is separated from the gas in surface equipment. The solvent is then regenerated by cooling and elemental sulphur is recovered by crystallization and filtration, while the regenerated solvent is pumped back down into the well.

The DSR technology is also well suited for surface type applications where sulphur deposition occurs in gas flow lines, surface equipment, or even transportation pipelines. The DSR Development Program covered a large range of operating conditions that represent almost any desired application: well or surface type or both combined.

A surface pilot was successfully operated in Texas during 2009. The testing program provided valuable design, operational, HSE and scale-up information that translate well

to a field demonstration and commercial applications. This testing validated laboratory results, allowed optimisation of the technologies that were pre-selected for the DSR unit. It also covered analysis of the produced sulphur and validation of the sulphur purification process.

Total and CrystaTech are currently pursuing a pilot scale demonstration of the DSR technology, to prove the process over long term operation, develop commercial scale-up and validate economic data.

The DSR process is expected to be the most cost effective method to produce natural gas from wells from medium or large sour gas fields with the potential for sulphur deposition.

1. INTRODUCTION

With the increase of the environmental awareness at a global scale, natural gas has become the fossil fuel of choice to meet the worldwide energy demand. With sweet conventional gas reserves declining, the oil and gas industry are facing new technical, safety and economic challenges associated with the sour nature of some of the large gas reserves. These challenges are associated with the stringent environmental and safety regulations with tight sales gas specifications for the development of gas fields with large amounts of hydrogen sulphide along with other sulphur components including, but not necessary limited to, mercaptans and carbonyl sulphide.

Additionally, if present in the well stream, elemental sulphur may deposit leading to other operational, safety and economic concerns that would require careful attention by oil and gas operators. A number of reservoirs may be listed as examples such those located in Europe (France and Germany) and North America (Alberta, Wyoming and Mississippi). The worldwide experience with sulphur deposition varies with the size of the field and with the amounts of deposited sulphur and the associated issues (corrosion, lost production, etc.).

Significant process developments have been achieved for years for the mitigation and the management of natural impurities (alkanolamine based sweetening processes, adsorbents, membranes, etc.) but relatively little efforts have been put together for the mitigation of sulphur deposition onto surface or subsurface for large sour gas fields. Current approaches focus on throw-away solvents and well treatments that require production outages. Given the serious implications on gas production, Total and CrystaTech have together proactively developed a regenerable physical solvent based process: DSR (Patent pending, publication number 20060043002 and 20090136414). A surface pilot has been successfully operated in Texas during the summer of 2009 and the technology will now be demonstrated in a field pilot. This paper presents the development results and key features of the DSR technology along with key conclusions from the surface pilot testing. This paper provides additional information from the initial DSR paper presented at the International Petroleum technology Conference held in Doha, Qatar, December 2009 [1].

2. BACKGROUND INFORMATION

The previous paper [1] provided a thorough understanding of sulphur behaviour in a sour natural gas and an accurate prediction of sulphur properties throughout the entire production path. The following paragraphs provide a summary of this previous work.

When sour gas is produced from a reservoir, both pressure and temperature decease, which in turn reduces the sulphur solubility in the gas. Once certain conditions are obtained in the well or in surface equipment, saturation is reached and sulphur appears in a free form, liquid or solid depending on temperature. Both liquid and solid sulphur can lead to corrosion damage in presence of brine. The solid sulphur can deposit in the well, flow lines or on surface equipment and can cause gas production to diminish and ultimately stop. However, non-thermodynamic factors such as kinetics or hydrodynamics can influence the ability of the gas to carry free elemental sulphur and may delay precipitation.

The above adverse effects resulting from the presence of elemental sulphur in sour gas can be extremely devastating. It is crucial for operators to implement a reliable mitigation strategy that covers normal operating modes and transient regimes for the entire production life. Total and CrystaTech’s objective was to develop a simple, cost-effective process that is HSE friendly for the mitigation of significant sulphur deposits where current technologies present economic limitations.

3. DSR TECHNOLOGY, DESCRIPTION AND DEVELOPMENT

3.1 DSR Principle

DSR was designed to employ a non-aqueous physical sulphur solvent that is capable of preferentially removing elemental sulphur from sour gas under a wide range of conditions. DSR solvent is thermally regenerable by cooling and provides high sulfur solubility which equates to low pumping cost. The design features standard and simple equipment that can be easily installed and operated in nearly any location offshore or onshore and that can mitigate sulphur deposition on the surface or subsurface.

In all cases, the solvent dissolves the sulphur from the gas. The sulphur-rich solvent is then separated from the gas and is regenerated by cooling. Elemental sulphur is recovered by crystallisation and filtration. Cooling is achieved via a suitably selected media that will depend on the site conditions. The regenerated solvent is pumped back to the injection points to dissolve additional sulphur and then can be re-utilised in subsequent cycles of the process.

Below two examples of DSR are presented in Figures 1 and 2, however other configurations are possible that may involve solvent injection in multiple locations subsurface and on surface.

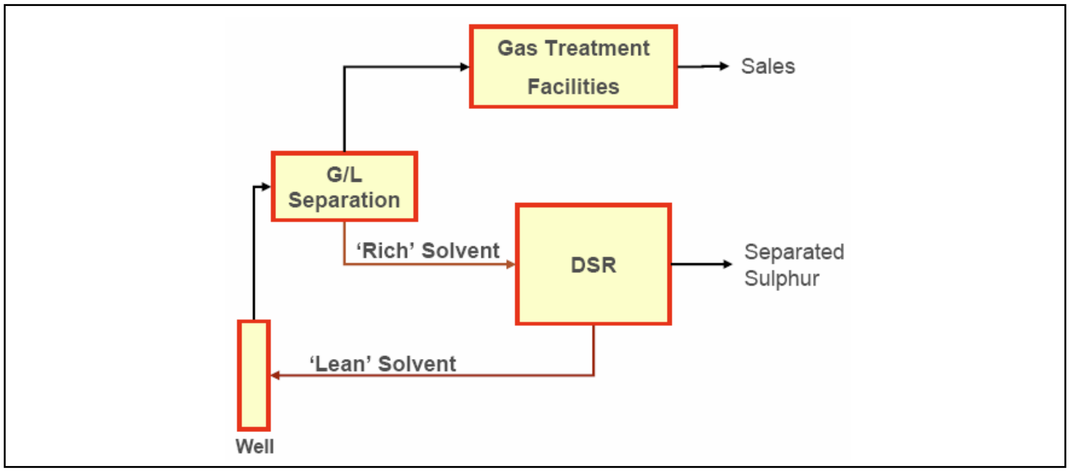

Figure 1 Sour Gas Production with DSR with subsurface injection

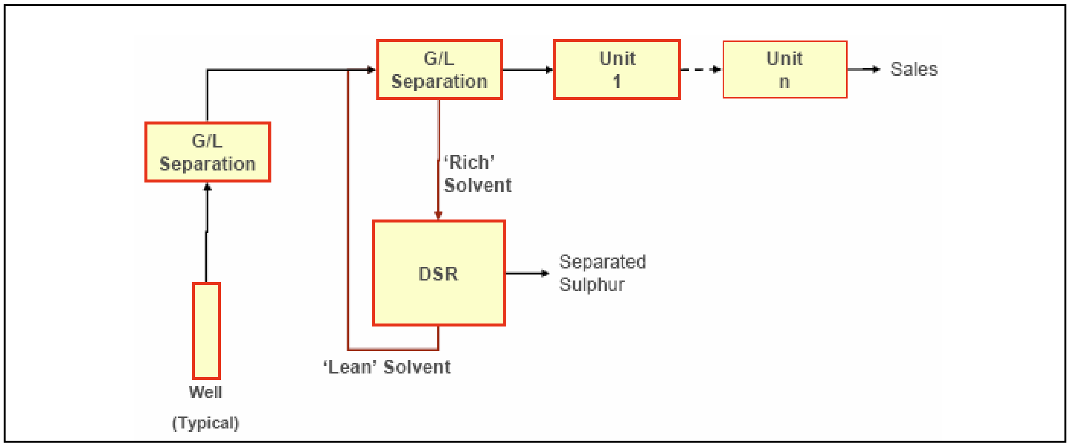

Figure 2 Sour Gas Production with DSR with surface injection

3.2 DSR Solvent

The core feature of the process lies in the solvent characteristics. The selection process involved substantial and rigorous testing to ensure robustness of the process over a wide range of operating conditions that represent both typical well and surface facilities.
The main technical screening criteria are summarised as follows:

- High sulphur pick-up capacity
- Easy thermal regeneration by cooling
- Chemically and thermally stability under well and surface conditions
- Low solvent losses (i.e. low vapour pressure at plant inlet conditions)
- No corrosive issues
- Suitability of physical characteristics (viscosity, density, vapour pressure at well conditions)
- Suitability for Health, Safety & Environment requirements (e.g. toxicity)
- Commercial availability at acceptable cost

The sulphur pick-up is defined as a comparison between the solubility ($S_{solvent}$) of sulphur in the solvent at two sets of conditions, as follows:

$\Delta S_{Solvent}(T,P) = S_{Solvent}(T_0,P_0) - S_{Solvent}(T,P)$; S being measured in weight percentage.

This parameter compares the solubility $S_{solvent}$ of sulphur in the solvent at T and P conditions to its solubility at reference conditions $T_0 > T$ and $P_0 > P$. T_0 and P_0 can represent, for example, down hole conditions. A large value indicates that the solubility of sulphur is low at low temperature and therefore elemental sulphur precipitates from the solvent and the sulphur is not bound in the solution. A low value indicates either the overall solubility of sulphur is low or the sulphur is bound in the solution and regeneration of the solvent will be more difficult. Figure 3 below illustrates the solvent pick-up between typical sulphur absorption (at high pressure HP and high temperature HT) and solvent regeneration conditions (at low pressure LP and low temperature LT).

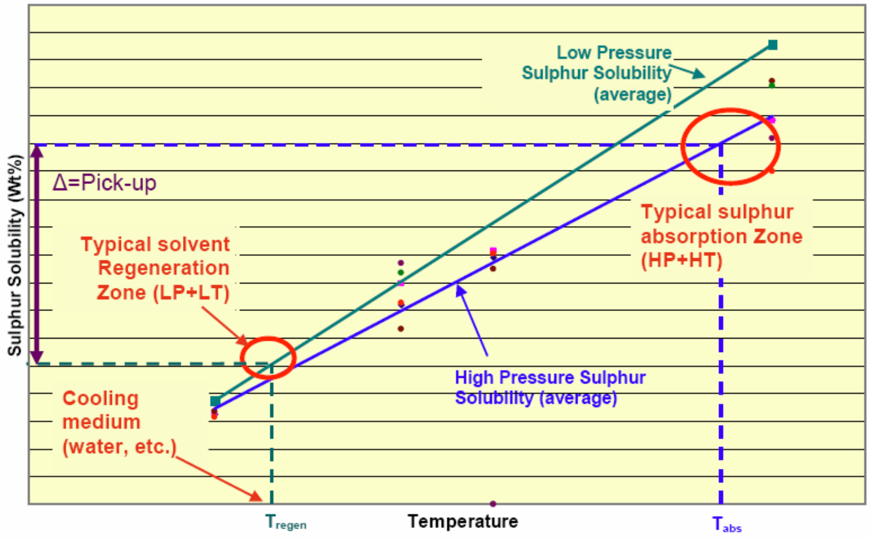

Figure 3 DSR typical conditions

The tested conditions covered a temperature range of 20-150°C with pressures as high as 238 bar on methane gas containing large amounts of H_2S up to 30 Mol.% in the presence of CO_2 and water. More details on the solvent screening programme were provided in our previous paper [1].

The solvent determines predominantly the economics of the mitigation measure:

- Good sulphur pick-up capacity will involve low quantities of solvent, leading to smaller equipment and low operating costs. On the contrary, poor pick-up will lead to larger installations and higher operating costs.
- Losses due to separation or due to degradation will impose continuous make-up of fresh solvent and will contribute to the operating expenditures.

To ensure the process is economically viable, the selected solvent formulation was also subjected to severe degradation tests at 80-250°C. Above 120°C, sulphur is vapour (i.e. cannot deposit), thus there is no need for the DSR solvent at this location. In practise, this means that for a DSR scheme whereby sulphur removal from a well is required, and where the bottom hole temperature is for instance at 150°C, there is a significant saving in pumping requirements as the solvent will not be injected at the bottom hole but at a depth where the temperature is around 120°C and where the pressure is below BHP.

However, the program aimed at enlarging the range of testing conditions to cover a variety of scenarios as much as realistically possible. For instance, in some cases, some gas components may be miscible with the DSR solvent and may tend to reduce the solvent sulphur pick-up, this leads to higher solvent injection rates to compensate for this effect. An economic consideration may suggest separating these components from the solvent at very high temperatures that may exceed bottom hole temperatures.

Overall, the degradation results indicate very little losses and confirm the basis that has been adopted for the economics of the DSR. The degradation testing results confirm a worst case scenario of a degradation rate of 2.0 10^{-5} (hour^{-1}), i.e., a degradation of no more than 2-3% of the inventory of DSR solvent can be expected to degrade over a full year. This is an extremely low degradation rate. It is calculated with consideration to the fact that the DSR solvent will only spend a limited time at the elevated temperature of 150°C. In the event of higher exposure temperatures such as 250°C, then the degradation remains reasonably low at around 13% of the starting inventory volume. In this case, the makeup of fresh solvent required to compensate for degradation losses is only a very small fraction of the injection rate (approximately 0.02%).

The effect of exposure to high temperatures and degradation on viscosity of the solvent continued to be investigated and evaluated (Figure 4). The results indicate that there is a small effect in the range of normal operating envelope of the DSR process. When exposed to extreme temperatures, there is a notable increase of viscosity over time but is still low enough to be easily managed as the exposure time is typically limited to around 1%. In reality, the total makeup rate will also account for losses resulting from gas-liquid or liquid-liquid separations or losses with the filtered sulphur and therefore will be larger than the degradation rate maintaining the overall viscosity within a very acceptable range.

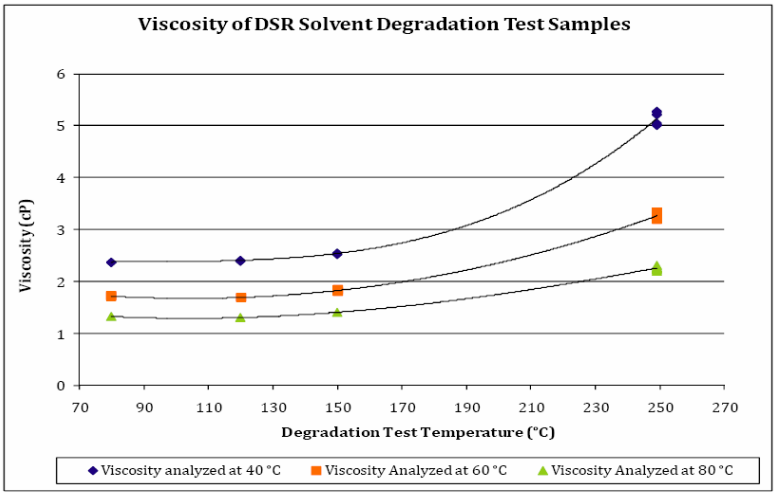

Figure 4 Viscosity of DSR solvent at 40°C, 60°C and 80°C after exposure to high temperature conditions (80-250°C).

Unlike the existing commercially available sulphur solvents used in other technologies such as amines, hydrocarbon oils or organic disulphides, the selected solvent for the DSR process is a more “operator friendly” solvent due to its physical and chemical properties: it does not exhibit a strong odour and is easily handled in operation as confirmed during the surface pilot testing program, which is described later in this paper. The DSR unit will be typically required for sour gas reservoirs and therefore will be installed at sour gas plants, requiring no special or extra HSE precautions other than those covered by routine HSE already associated with high-pressure sour gas plants.

Overall, the test program was successful in identifying a formulation for the DSR process that has proved to have all the required properties and to meet the objectives of the development programme.

3.3 Thermodynamics and Modelling

Thorough modelling of the DSR process can be a challenge especially for subsurface conditions where the operating conditions change significantly from bottom hole up to surface over a wide range of pressures and temperatures. As discussed below, the challenge comes from the variety of sulphur species that are present in a sour gas containing elemental sulphur and from the potential reactions which may occur. A further complication may come from other reactions like those involving carbonyl sulphide.

Sulphur can be present in different allotropes, S_n. Under typical sour gas reservoir conditions, the most stable form is the S_8 cyclic ring. The proportions of the different allotropes are temperature dependent. Therefore, they vary throughout the production path as the temperature evolves.

Elemental sulphur in sour gas reacts with hydrogen sulphide to form various hydrogen polysulphides H_2S_n (very often called sulphanes). The sulphanes have been known since the eighteenth century, but have only been recently characterised and there is still limited quantitative information available. Sulphanes are very sensitive to their environment and can rapidly decompose with the formation of sulphur and hydrogen sulphide. In absence of any other chemical agent (bases, metals, etc.), their stability is mainly temperature and pressure dependent (partial pressure of H_2S) and their formation is favoured by high pressure and temperature.

Under typical sour gas production and processing operating conditions (i.e. at temperatures up to 150°C), sulphur species are mainly in the range between S_2 and S_8 allotropes with the most abundant species being S_6, S_7, and S_8. Under the same conditions, hydrogen sulphide and disulphane are predominantly present in comparison with the other sulphanes.

The sulphur solubility in a sour gas is a function of all the above parameters, (i.e. temperature, pressure, H_2S content) and is also related to the presence of aromatics. The added hydrocarbon liquids can dissolve sulphur to a certain extent but also alter the freezing point of sulphur. The above chemical reactions help increase the sulphur solubility in a sour gas that is even more pronounced at very high concentrations of H_2S.

Accurately predicting gas saturation and sulphur precipitation conditions requires rigorous calculations that include the elemental sulphur content of the gas and the thermodynamic properties of various sulphur species, particularly the sulphanes. These predictions are almost impossible because it is difficult to determine their speciation experimentally. Furthermore, this data is currently not available in commercial software packages so an extensive thermodynamic model was developed within Total.

Chemical and phase equilibrium must be modelled simultaneously in the reservoir but most of the reactions are quenched along the production pathway. Therefore the precipitation of elemental sulphur in a sour gas during production can be obtained from a simple phase equilibrium calculation. The transition between liquid and solid sulphur phase can also be obtained from thermodynamic calculation but there is a lack of reliable data on the mutual solubility of sulphur and hydrocarbons under high H_2S partial pressure. The sulphur solubility in a sour gas depends mainly on H_2S content, pressure and temperature.

The thermodynamic in-house model was developed with all the above considerations in mind. The model has reached a good level of maturity and allows good representation of the speciation, sulphur solubility in sour gas, precipitation conditions with credit to full fluid composition (effect of H_2S, hydrocarbons, aromatics, etc.) & operating conditions (T, P). The current model allows calculation of required solvent flow rate for known reservoir fluid. In the figures below are examples of results that can be obtained with the model.

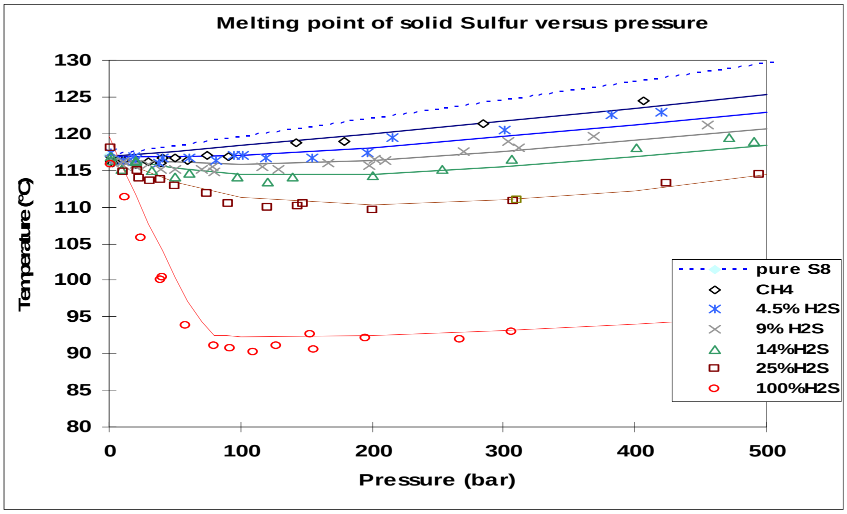

Figure 5 Melting point of Sulphur in mixtures of H_2S & CH_4

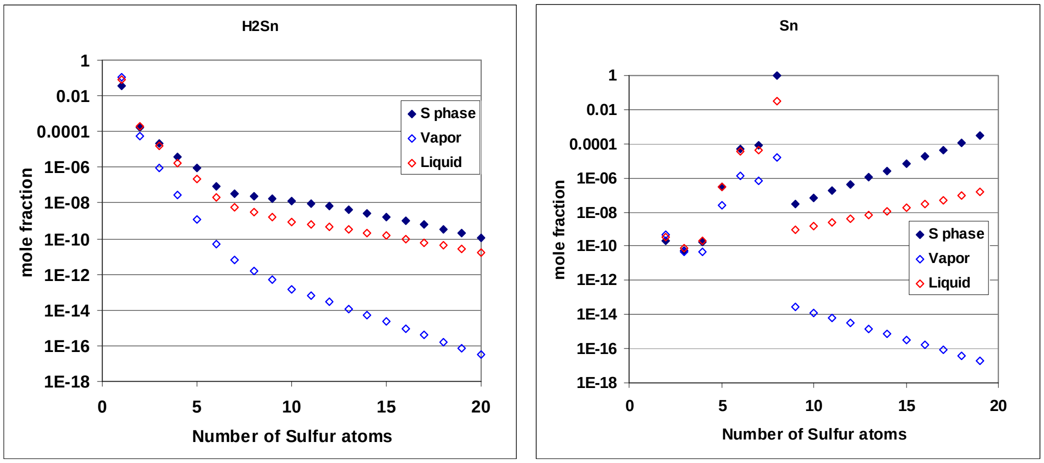

Figure 6 S_8, H_2S, CH_4, CO_2 mixture at 100 bar 150°C:
S_n and H_2S_n distribution in the various phases

3.4 Surface Pilot

This section is intended to complement our previous paper [1] and to provide more detailed information and results regarding the surface pilot testing in Georgetown, Texas in the period between July and October 2009.

The key mechanical element of the DSR process is associated with the crystallisation and separation of elemental sulphur from the solvent once separated from the gas stream. Although various crystallisation methods are in use in the industry, there is little or almost no experience with crystallisation in the oil & gas industry. This technique may be employed for a number of applications and is believed to be an innovative approach. In absence of a suitable field well for the application, a surface pilot test was performed which was a simple and cost-effective approach to provide valuable insight to future larger designs at a minimum risk. A surface pilot was also the opportunity to test at reduced cost various filtration techniques under different sets of conditions. The surface pilot was designed to simulate the solvent sulphur loading, regeneration and solids handling. Direct contact with high-pressure sour gas was not part of this testing, which allowed for design simplification due to the greatly reduced HSE issues.

The surface pilot was installed in Texas and was operated from July to October 2009. During this period, over 280 hours of operation were obtained under different operating parameters. The capacity of the unit was designed and operated between 7.5 and 13 litre/minute solvent circulation rate and had a maximum production of sulphur of 0.7 tons/day. Most testing was performed in 8 to 10 hour intervals but a long term test was performed and achieved 98 hours of continuous operation.

As represented in Figure 7, the design of the surface pilot features three main sections that constitute the loop of testing:

- A first section made of tanks whereby sulphur is dissolved in solvent and sufficiently heated to prevent from premature precipitation, i.e. prior to the crystalliser.

- A second section consisting in the crystalliser unit and associated cooling facility.
- And a third section dedicated to sulphur separation and filtration.

Solvent and excess elemental sulphur are heated and mixed in the dissolution tank. The temperature of the dissolution tank is controlled to set the sulphur saturation level of the solvent to loadings expected for the process. Saturated solvent overflows a weir, to minimise solid sulphur entrainment to the ‘super heater’ tank where sulphur loaded solvent is further heated before being pumped to the crystalliser. The temperature in the super heater tank is controlled to expected operating temperatures at the well head. That sulphur loaded solvent is pumped to the crystallizer where cooling causes sulphur to crystallise. The slurry of sulphur exiting the crystalliser flows to the slurry tank where the continuous circulation from the cone and returning to the slurry tank maintains suspension of the slurry and prevents plugging. From there, the slurry is either pumped back to the dissolution tank or is routed to the filters. All equipment is insulated and all piping is heat traced and insulated.

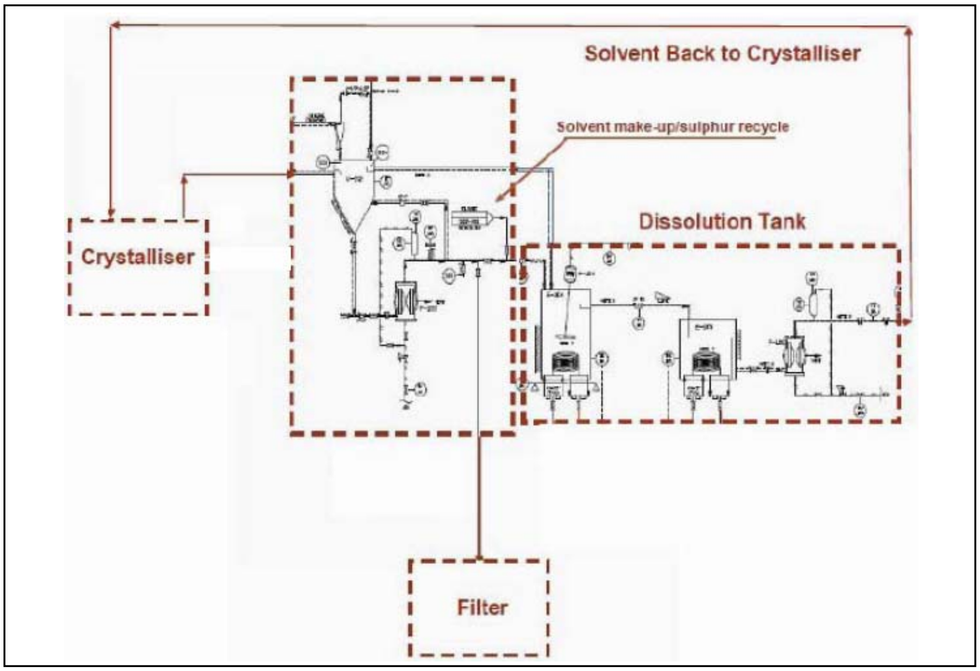

Figure 7 Surface Pilot Unit simplified scheme

After completion of the testing, all equipment was inspected: no corrosion/erosion damage was observed. However, the test conditions did not involve sour gases such as H_2S/CO_2 or chlorides. The planned field pilot testing will include corrosion coupons and probes that will allow optimisation of equipment metallurgy and use of corrosion inhibitors.

3.4.1 Crystallisation

Various crystallisation techniques have been previously investigated to ensure a robust method is selected since crystal formation is at the heart of DSR. One key to good crystallisation is to have adequate nucleation sites of sulphur which reduces crystal growth on unwanted surfaces, like vessel walls and piping. The design and operation of the crystalliser is related to particle size of sulphur crystals. Sulphur particle size is a critical parameter for the DSR process because it directly effects long term operation and sulphur separation. In addition, the DSR crystalliser design must have the following features and characteristics:

- Suitable for high solids throughput
- Suitable for large process fluid-coolant temperature differences
- Limited footprint
- Modular in design and flexible in operation

The size of the crystalliser that was tested is relatively small when compared with available commercial units but was carefully selected to provide sufficient information for scale-up purposes. From a process and operation standpoint, the residence time is lower than ‘normal’. This situation forces quicker crystal growth resulting in smaller solid particle size and potentially more difficult separation and filtration. However, there were no problems with filtration or separations experienced due to small particle size formation during the surface pilot testing.

Data obtained from the surface pilot testing was analysed using SAS-JMP statistical jump software. This analysis provides the confidence level in which the data is expected to be based on the number of gathered samples.

Below, Figure 8 is an example of the results. The data in Figure 9 shows the effect of solvent flow rate variation on particle growth and size. D(0.9) indicates the size of particle below which 90% of the sample lies. The effect over the range of flow rate test conditions was found to be negligible.

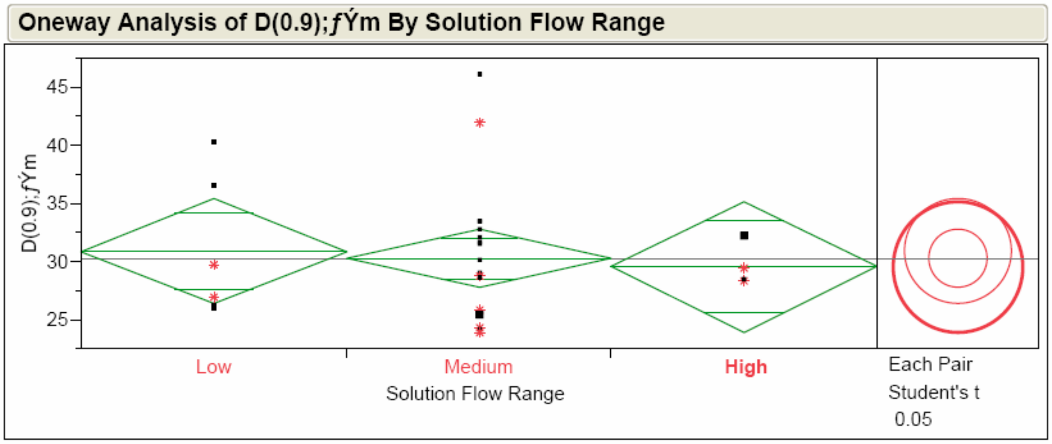

Figure 8 Particle size under low, medium and high solvent circulation rates.

The effect of process fluid temperature was found to have a minor effect on particle size as represented in Figure 9 below:

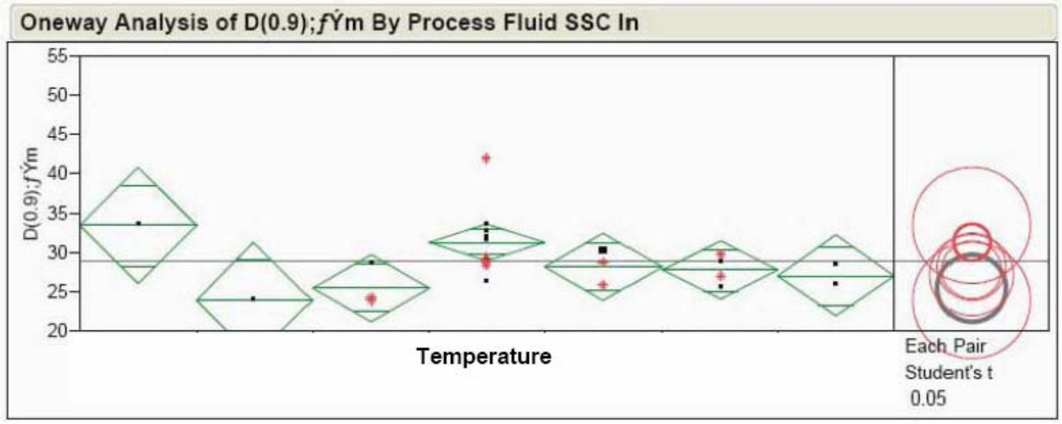

Figure 9 Particle size under various operating temperatures

Overall, the crystalliser has been tested over a number of conditions and sulphur has consistently crystallised with nominally the same particle size range of 20-45 microns.

3.4.2 Filtration

Three main sulphur filtration techniques have been pre-selected for DSR for their solvent separation performance and for the expected sulphur quality. If not designed for, the filtration of DSR solvent in commercial applications can be problematic due to the presence of hydrocarbon vapours, both light and heavy hydrocarbons, and dissolved H_2S in the circulating solvent which are absorbed from the gas. Therefore, minimum requirements for the filtration devices are:

- Filtration must be performed in a closed system.
- Purging of hydrocarbons and H_2S from the filtered sulphur must be possible.
- Ability for multiple solids washing steps.
- Vapour handling available for when product is discharged.
- Containment of liquids away from final product to minimize contamination if there are mechanical problems during filtering or filter cleaning steps.

The three styles of filters selected are vertical filter press, pressure filters, and centrifuge. See Figure 10 below.

Figure 10 From left to right: Filter press, Pressure filter and Centrifuge.

A summary table of the filters tested is provided in Table 1 below:

Table 1 Filters and characteristics at the surface pilot

	Filter Press	Pressure Filter	Centrifuge
Manufacturer	Andritz	Oberlin	Western States
Design comments	Vertical membrane	Indexing belt pressure filter	Perforated bowl centrifuge
Tested filter area	4 135 cm^2	290 cm^2	1 700 cm^2
Filter media	Woven polypropylene	Woven polypropylene	Woven polypropylene
Average Cake thickness	25 mm	50 mm	50 mm
Cycle time	50 min	20 min	30 min

Each of the filters tested worked well from a solid separation standpoint and did not pose any mechanical problems during the test.

The collected samples were analysed for:

- residual organic as total carbon & residual moisture
- particle size distribution

The filters were also assessed with regard to:

- ease of operation
- cake permeability
- cake handling
- cycle time

The particle size distribution of the sulphur samples was determined using a Malvern Masteriser 2000 unit that uses light diffraction to determine the size of dry powders. Figure 12 shows the average particle size distribution of the samples collected from each filter and a sample that was filtered in the laboratory using a 0.5 micron filter paper which is represented by “No Filter”. The overall particle size distribution for all filters is within reasonable agreement; however there was a noticeable shift in the distribution of the filter press. The results from the filter press indicate more small particles were not captured and could result in a slightly increased pump rate as this sulphur would re-dissolve and reduce the overall $\Delta S_{Solvent}$. Figure 11 provides further proof of this shift through analysis of variation (ANOVA) of the data sets.

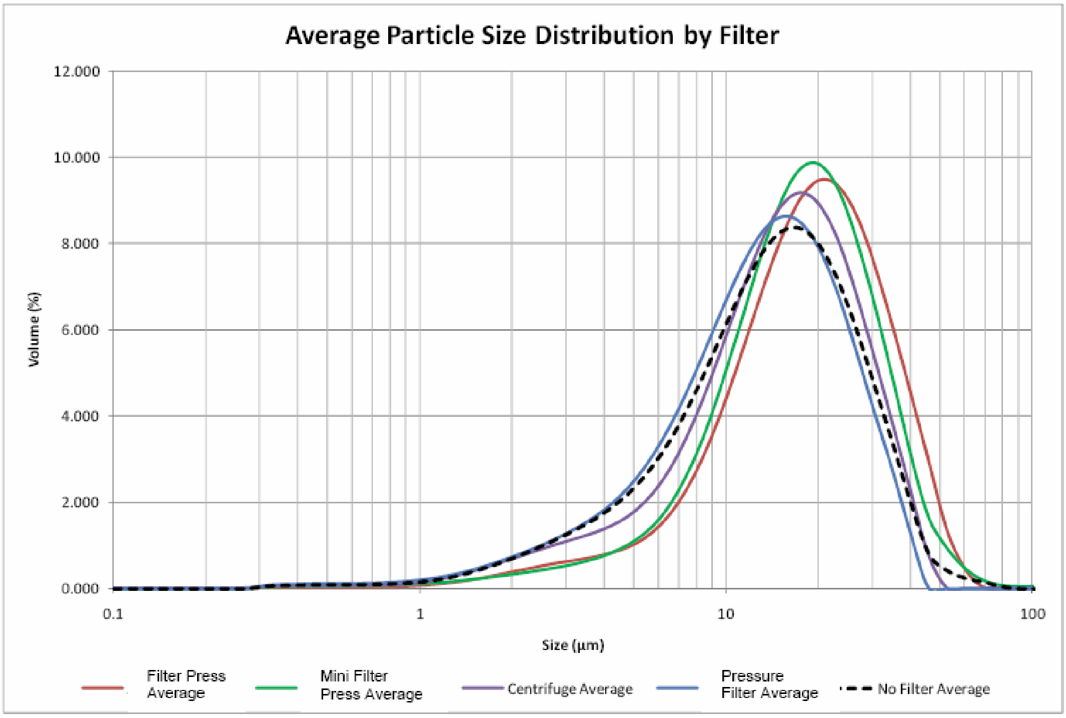

Figure 11 Particle size distributions (Avg) of separated sulphur with different filters

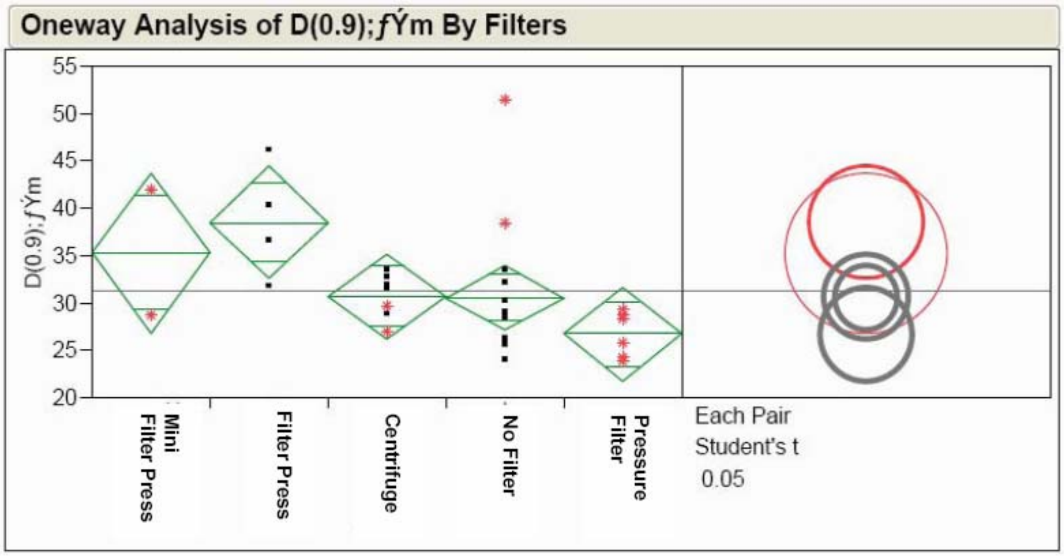

Figure 12 Particle size analysis of variation of sulphur separated with different filters

The total moisture (TM) is another typical filtration quality parameter but in this case includes both the water moisture and residual wash solvent. This is due to the light hydrocarbon used has a similar boiling point as water and the weight loss after drying the sample at 100 °C will include both water and wash solvent. Further analysis was required and it was determined that the contribution due to the light wash solvent was negligible and the TM represented water on the sulphur cake. The analysis shown in Figure 14 indicates that the lowest TM values for the centrifuge technology and highest for the pressure filter.

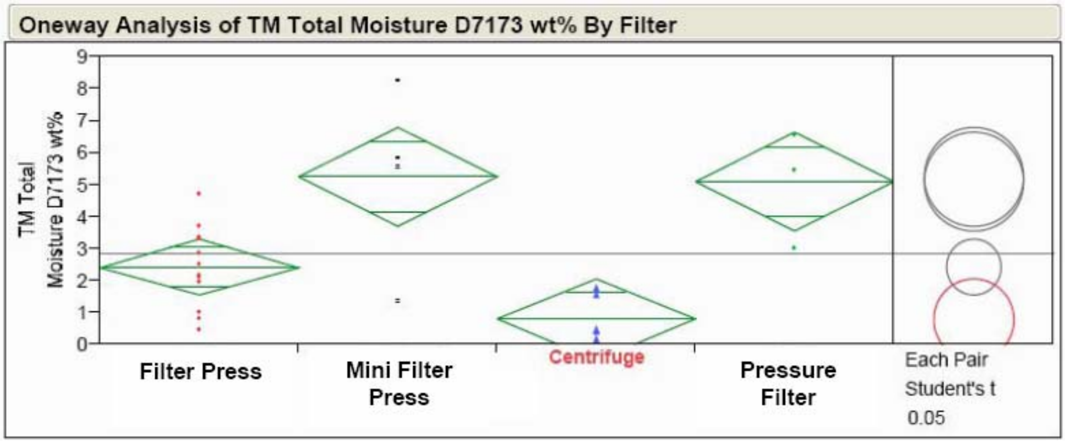

Figure 13 Total Moisture in separated sulphur with different filters

The CTMF, Carbon Total Moist Free, is the other important if not the most important parameter that is of interest to a sour gas integration scheme where sulphur is produced from conversion of hydrogen sulphide (e.g. Claus). CTMF indicates the residual carbon remaining on the sulphur cake from the DSR solvent. Low CTMF will allow for disposal options including blending of DSR sulphur with the main sulphur stream as produced from sulphur recovery units. The promising results obtained from the surface pilot testing show that the filtered sulphur from the centrifuge contains less than 0.15 wt% carbon, and is shown on Figure 14.

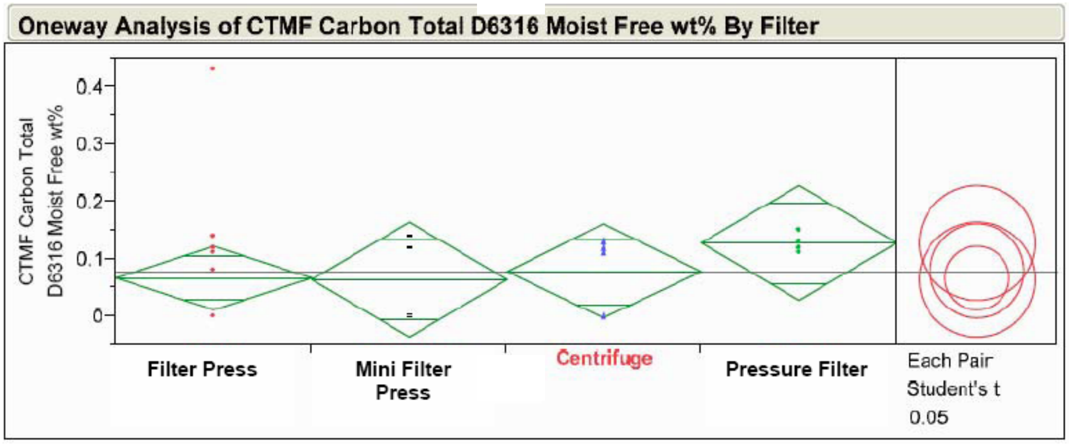

Figure 14 Carbon Total Moist Free in separated sulphur with different filters

Different wash protocols have been tested, evaluated and compared with regard to residual water and hydrocarbons in the sulphur samples. As detailed above, the test conditions represent a worst case scenario as sulphur particles are relatively small due to the short length of the crystalliser unit tested. However, sulphur handling, solids settling and filtering test results were very positive and translate into results that indicate the need for smaller tanks and filter areas than initially predicted.

4. DSR PRELIMINARY COST INDICATIONS

A preliminary capital and operating cost estimate (CAPEX/OPEX) is described in this section for the implementation of the DSR process for the treatment of well bores to prevent sulphur deposition during gas production. Three cases are presented and discussed hereafter. A comparison with a typical once-through process is also discussed for each of these cases - whereby the solvent is not regenerated and is disposed off. These cases and subsequent costs imply treatment of several wells utilising a central treating facility.

Table 2 Study cases for the cost study

	Unit	Case 1 'Low'	Case 2 'Medium'	Case 3 'High'
Raw Gas flow rate	MMScfd	200	500	1 000
	$MMSm^3d$	5.663	14.158	28.316
H_2S content (Mol. %)		15	35	40
CO_2 content (Mol. %)		6	10	10
Elemental sulphur content	lb/MMScf	30	145	240
	g/Sm^3	0.48	2.32	3.84
Number of wells		5	20	55
Solvent injection network length	km	15	50	75
	mile	9.3	31	46.6

The CAPEX for the once-through approach was prepared assuming a similar arrangement as for the DSR, i.e., a centrally-located tank farm for receiving fresh chemical and offloading spent chemical. In this arrangement, there is still a high pressure separator and metered injection pump (one duty and one spare) at each well cluster. The tank farm is equipped with a booster pump to supply the fresh chemical to the injection pumps. A one week supply of fresh chemical is assumed to be on hand and enough tank capacity to hold one week of spent chemical. In addition, there is no allowance for utility, maintenance or manpower requirements; the OPEX is limited to the chemical costs. Due to the equipment simplicity, these expenses are deemed to be negligible over the high chemical costs.

For the purpose of this comparison, it is conservatively assumed that the once-through solvent has a better sulphur pick-up than the DSR solvent with an extra 50% pick-up capacity. This assumption is conservative, in favour of the once-through approach, given the results that were obtained at a laboratory scale and verified at the DSR surface pilot testing. However, the impact of stream impurities from the well on the DSR process is not completely understood and requires a field pilot unit to generate this information.

The OPEX presented for DSR includes the chemical operating costs, utility and maintenance costs and labour. The treatment costs for both cases do not take account amortisation of the CAPEX. In addition to these costs, the gas will still require further treatment before it could be used or sold due to the remaining H_2S content.

Table 3 Comparative results of CAPEX and OPEX between DSR and Once-through

	Case 1 'Low'		**Case 2 'Medium'**		**Case 3 'High'**	
Technology	DSR	Once-through	DSR	Once-through	DSR	Once-through
CAPEX	100	50	100	55	100	50
OPEX	100	340	100	200	100	390

Due to the large volumes and chemical usage costs, a once-through approach for managing well bore sulphur deposits is not feasible in the sulphur loading range that was examined. As shown in Table 3, the DSR process technology shows significant savings over the once-through process, even using the conservative assumptions mentioned previously.

Typically, the capital investment for a once-through design is 50% less than that of a DSR unit; however the operating expenditures are 2 to 4 times higher than those for the DSR process. The economic advantage of DSR is consistently proven over a wide range of conditions. The next steps for confirming these costs are to embark on the demonstration unit and gather real time operating data.

5. CONCLUSIONS

For large gas producing fields where elemental sulphur is present in the well stream, sulphur deposition is a serious concern that requires full attention as it can result in significant operational, safety and economical issues (corrosion, pluggage, etc.). Sulphur management in large sour gas fields will outgrow the economic viability of current technologies and require amounts of sulphur solvent that may pose significant negative economic and environmental impact. For this reason, Total and CrystaTech have jointly developed the DSR process to minimise these issues.

The DSR technology is a regenerable solvent based process that was originally developed to mitigate large sulphur deposits in wells but is also well suited for surface type applications where sulphur deposition occurs in gas flow lines, surface equipment, or even transportation pipelines. The surface pilot testing program provided valuable design, operational, HSE and scale-up information that translates well to a field demonstration and commercial applications. This testing validated laboratory results and allowed optimisation of the technologies that were pre-selected for the DSR unit. The surface pilot testing also covered analysis of the produced sulphur and validation of the sulphur purification process.

The economic analysis as detailed in this paper indicates that the DSR technology is the technology of choice for the mitigation of sulphur deposition during production of sour gas from large fields.

The technology is now ready to be implemented in a field pilot. This single well application will be used to develop commercial scale-up and economic data.

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NOMENCLATURE

BHP	Bottom Hole Pressure
CAPEX	Capital Expenditures
CTMF	Carbon Total Moist Free
DSR	Downhole Sulphur Recovery
HP	High Pressure
HSE	Health, Safety and Environment
HT	High Temperature
LP	Low Pressure
LT	Low Temperature
OPEX	Operating Expenditures
P	Pressure
S	Sulphur solubility in a solvent (expressed in weight %)
T	Temperature
TM	Total Moisture

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