HANDLING OF CORROSION AND SCALING SHORTCOMMINGS IN LOW ENTHALPY GEOTHERMAL ENVIRONMENTS

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ABSTRACT

This paper addresses the well and near well formation damage mechanisms encountered on geothermal district heating wells producing/injecting low to medium temperature brines in an aqueous CO_2/H_2S environment. Corrosion of exposed metal surfaces and forming of heavy metal sulphide and calcium carbonate scale are reviewed. Remedial strategies based on material definition (removable fiberglass lining of metal casings) and downhole chemical inhibition technologies are presented and monitoring/economical aspects are presented in fine.

1. INTRODUCTION

Geothermal fluids often display hostile thermochemical characteristics resulting in well/ formation damage and failures of surface equipment which severely penalize exploitation economics.

Damage occurs in the form of metal corrosion and deposition on material surfaces of scale species. Both phenomena may also coexist through deposition and/or entrainment of corrosion products. Most commonly encountered damage addresses CO_2/H_2S corrosion, alkaline carbonate/ sulfate, heavy metal sulphide and silica scale. Source mechanisms are governed by pH, solution gases and relevant bubble point and (CO_2) partial pressures, salinity, solubility products and modifications of thermodynamic conditions induced by the production and injection processes.

Whereas scaling affects mainly high enthalpy systems as a result of fluid flashing, steam carry over and injection of heat depleted brines, corrosion and, at a lesser extent though, scaling are the major drawbacks in exploitation of low grade geothermal heat. Microbiological activity, particularly sulfate reducing bacteria, can also be a significant corrosion contributor in such low temperature environments.

In the Paris area, casing corrosion, caused by a dissolved gas phase, enriched in CO_2 and H_2S interacting with the metal lattice, dramatically impacted the early stages of geothermal developments. Out of the 50 district heating doublets initially in service, 14 were closed and abandoned as a consequence of irreparable well damage. Of the 36 remaining on line, 32 have been serviced by heavy workovers aimed at damage removal and further equipped with down hole chemical injection lines in order to erradicate, or at least slow down, the damaging process.

All together induced costs have amounted to ca 100 mio FRF (15 mio €s) of which 70 and 30 allocated to workover and inhibition equipment respectively. This represents approximately a unit unvestment cost of 350,000 FRF (53,000 €s) per installed MWt. On the other hand costs of chemicals are nearing 3 mio FRF/yr [i.e. ca 3 FRF (0.45 €)/MWht/yr)].

These figures indeed highlight a challenging compromise, how to reconcile technically feasible inhibition strategies with economically viable issues.

The present paper will illustrate the foregoing by reviewing the engineering of damage assessment, removal and inhibition, the technologies and monitoring protocoles involved alongside their economical implications, as experienced on the Paris basin geothermal district heating systems. This bearing in mind that similar strategies could in many respects be extended to diffe- rent low enthalpy geothermal resource and thermochemical settings in spite of the reportedly site specific nature of the problem.

2. DAMAGE SOURCE MECHANISMS. AN OVERVIEW

Corrosion and scaling of geothermal, ground water and hydrocarbon wells are widely documented in literature. In particular, references[1][2] provide comprehensive surveys focused on geothermal and oil field problems. Of particular relevance to geothermal fluids, in the low to medium temperature range, are iron corrosion in CO_2/H_2S aqueous solutions and carbonate scale which are frequently encountered in production/injection wells. These processes are outlined hereunder.

### 2.1 H_2S and CO_2 corrosion

H_2S corrosion of carbon steel in hot CO_2/H_2S aqueous systems is an electrolytic process by which iron is oxydized as (soluble) ferrous iron at the anode and H_2S dissociated into HS^- and $S^=$ ions at the cathode, according to the equilibrium reaction :

$$Fe + H_2S + H_2O = FeSx + 2H \tag{1}$$

Various crystal species will be formed and coat the casing. They evolve from unstable porous lattices (mackinawite) to stable indurated structures (pyrite).

Atomic hydrogen released by (1) may invade the steel through preferential discountinuities and accumulate to form molecular hydrogen and generate stress corrosion cracking.

CO_2 corrosion is a process of iron dissolution by carbonic acid governed by the set of equilibrium reactions below :

$$CO_2 + H_2O = H_2CO_3 \tag{2}$$
$$Fe + H_2CO_3 = FeCO_3 + H_2$$
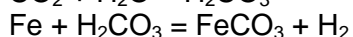
A derivation of H_2S corrosion concerns microbiological damage induced by sulfate reducing bacteria which are known to develop in pH and temperature environments of 5 to 8 and 60 to 80°C respectively. The mechanism by which sulfates are reduced is favoured by iron while bacteria act as depolarization agents, a process summarized in the following reactions :

$$4Fe + SO_4^= + 10H^+ = 4Fe^{++} + H_2S + 4H_2O \tag{3}$$
$$4Fe^{++} + H_2S + 6H_2O = FeS + 3Fe(OH)_2 + 8H^+$$
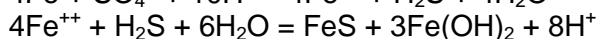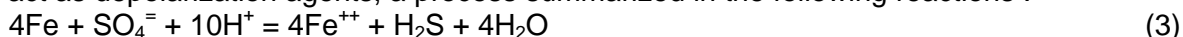
Iron displacement results in a localized, pitting type, attack.

2.2 Scaling

Formation of calcium cabonate and iron sulphide scale conforms to the following equilibrium reactions:

$$2HC0_3^- + Ca^{++} = CaCO_3 + CO_2 + H_2O \tag{4}$$
$$Fe^{++} + HS^- = FeS + H^+$$
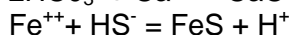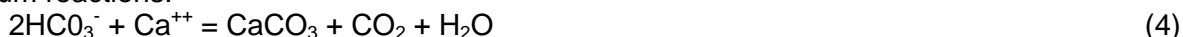
Chemical thermodynamics show that supersaturation and subsequent precipitation will occur if the saturation index SI verifies the relationship:

$$SI = \log (IAP / KSP) > 0 \tag{5}$$

where IAP and KSP are the ion activity and solubility products of the solid species respectively.

The scale and depositional processes which, very briefly, include various steps from nucleation and crystal growth to transport, deposition proper and aging, are described in[2].

3. DAMAGE DIAGNOSIS

There is a wide spectrum of methods for identifying and evaluating thermochemically induced well damage, among which ought to be distinguished:

3.1 Pressure/flow monitoring

It is a simple and obvious means of characterizing well impairment by losses in deliverability from nominal productivity/injectivity figures. These measurements can be usefully complemented by well testing and relevant pressure drawdown/rise and/or build up/ fall off analysis which will provide the bases for precise evolution of damage impact.

3.2 Direct damage assessment

It is performed via logging inspection based on multifinger caliper, ultrasonic or production tools. Casing calipers are reliable damage indicators which can achieve high resolution and accuracies thanks to 16 and even 40 simultaneously acquired radii values. Two way times from ultrasonic sources can also retrieve internal acoustic diameters, longer echos corresponding to wall piercing.

Material balance calculations carried out on logs completed after restoration workovers allow for estimating damaging kinetics (i.e. corrosion or deposition rates).

3.3 Chemical control

Analyses of liquid, gas and solid (suspended, deposited) samples enable to establish the fluid thermochemical profile and either validate or predict its corrosion/scaling tendancies.

Important in these respects are the PVT (table 1), the wet chemical (quantitative) and dry mineralogic (Xray diffractometry) (qualitative) analyses of water and scale samples collected at various in hole and surface localities. The example attached in table 1 demonstrates the poor reliability of the solution gas analysis carried out on the surface sample, even when collected at a pressure above bubble point.

Figure 1, which accounts for numerous solid samples, exhibits the dominant share of unstable and porous iron sulphide crystal species such as mackinawite and pyrrhotite[3][4].

Thermodynamic modelling will be further applied to match actual data, predict future damaging trends and design adequate inhibition procedures.
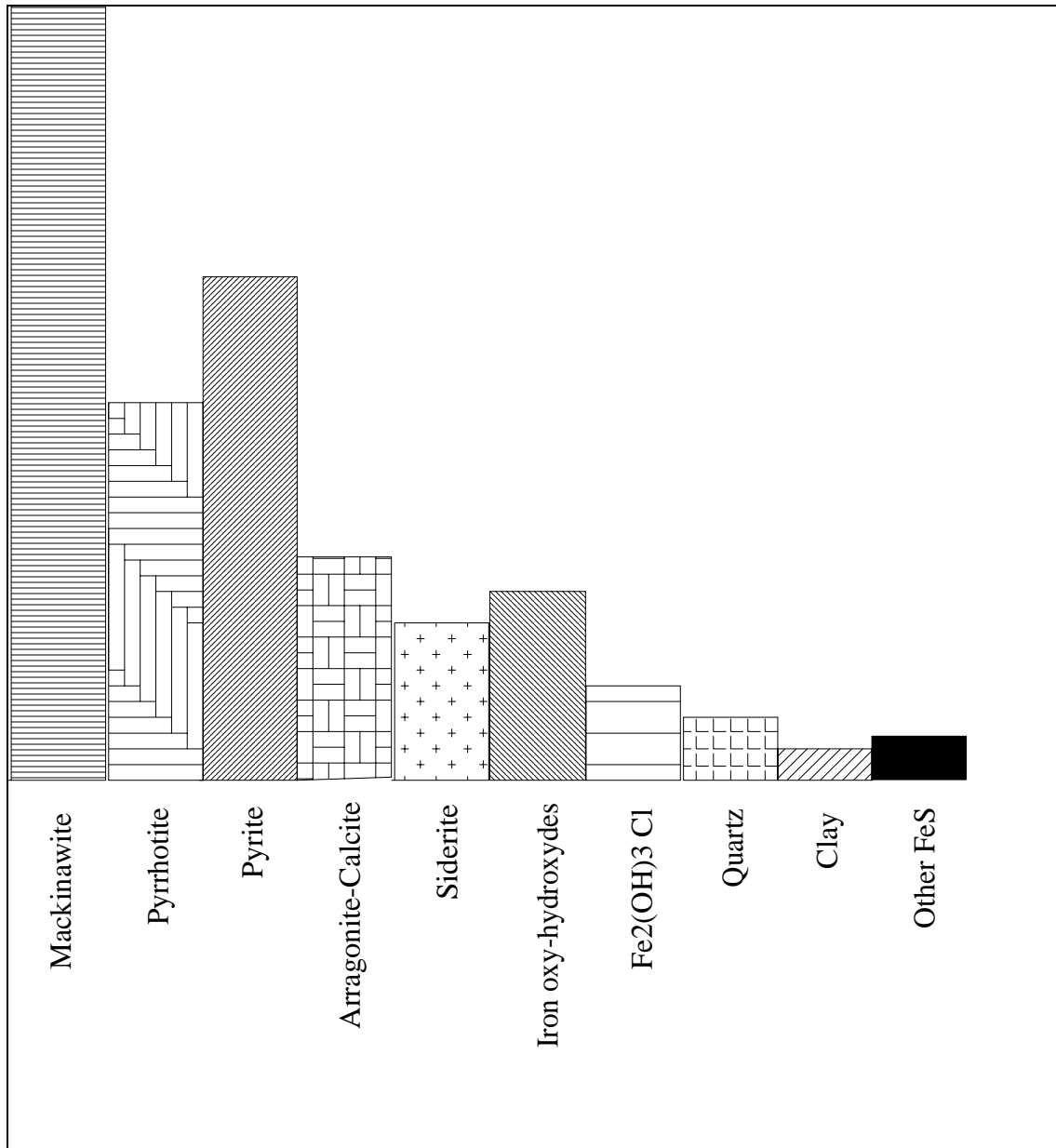

Figure 1: Diagram of scale species sampled in damaged wells. (source IMRG)

Table 1: PVT Analysis of Bottom Hole and Surface Samples

Sample n°	3	4	5	6	7
Depth (m bgl)	160	1,818	1,818	160	0
Pressure (kg/cm^2)	17	172	172	23	8,5
Temperature (°C)	62,2	64,2	64,2	60,2	63
Flowrate (m^3/hr)	158	46	46	46	125
Bubble point pressure (bars)	7.9	8.2	8.4	8.3	6.9
Gas liquid ratio GLR (vol/vol)	0.23	0.25	0.26	0.28	0.19
H_2S (% mol)	> 1	> 1	> 1	> 1	-
N_2 (% mol)	25.8	25.8	27.5	26.8	64.12
CO_2 (% mol)	51.09	52.3	51.18	52.7	1.07
CH_4 (% mol)	20.6	19.6	18.9	19.8	34.68
C_2H_6 (% mol)	1.49	1.50	1.40	1.70	0.13

4. DAMAGE REMOVAL AND PREVENTION

The conventional remedial strategy consists of cleaning the well by removing scale by either hydrojetting tools or rockbits driven by drill strings or coiled tubings (the latter being restricted by a limited flow capacity compared to drill pipe performance). In geothermal service and iron sulphide deposits (identified as corrosion products rather than native reservoir produced scale), the jetting concept described in[5] has been successfully applied.
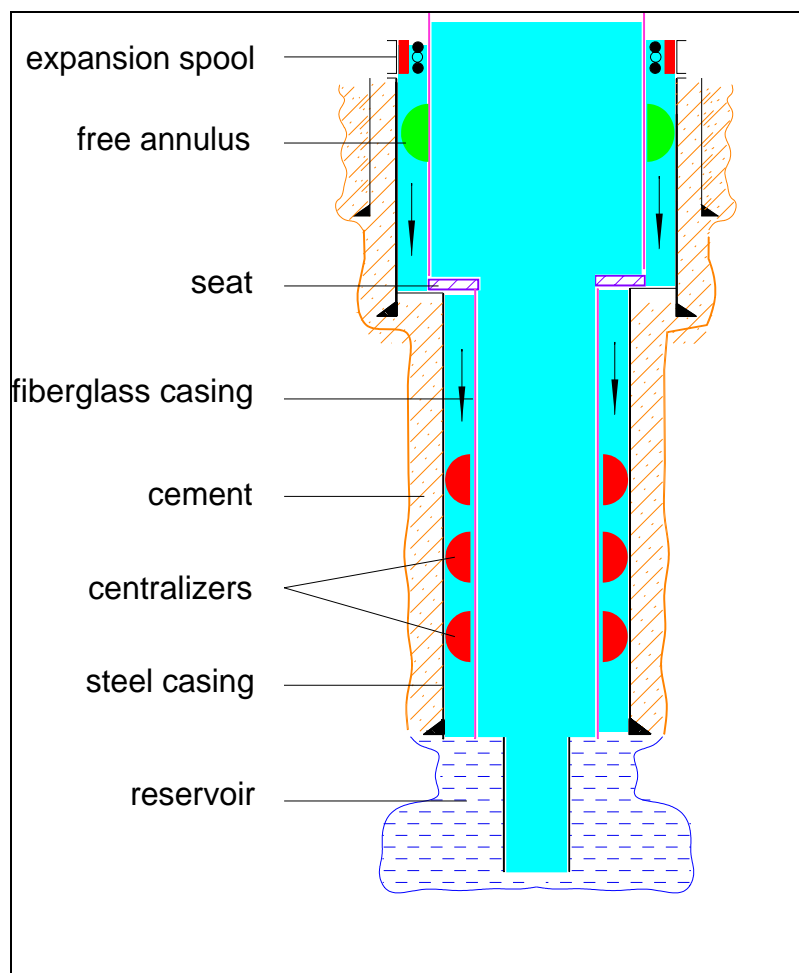
Figure 2: Combined steel casing/fiberglass lining well (WELCOM)

Another, recently tested, restoration procedure known as soft acidizing proved efficent on several damaged injector wells in the Paris area[6]. The technique consists of injecting continuously from surface highly diluted HCl solutions mixed with an iron sequestering additive. The injected acid volume is equivalent to that normally squeezed into the reservoir via a drill string in

conventional -petroleum/geothermal/ground water well- acid jobs. Only do injection times differ - 60 hrs against 1 hr- and the etching process alike which, in the conventional procedure, concerns the reservoir alone whereas soft acidizing addresses both well casing and/or formation damage.

Material definition would seem the most appropriate route for defeating corrosion. Fiber glass/ epoxy resin composite casings or liners are valid candidates provided temperatures remain below glass transition temperature (105°C) and that well inclination does not exceed 35°. The concept illustrated in figure 2 and implemented on a Paris basin geothermal site[7] offers an additional capacity of circulating chemical inhibitors via the steel casing/fiberglass lining annulus.

Chemical inhibition is another alternative which requires suitable injection (especially downhole) technologies, adequate selection of candidate inhibitor agents and monitoring/evaluation protocols. Needless to say the foregoing have to prove cost effective as regards the often sensitive exploitation economics of low grade geothermal heat.
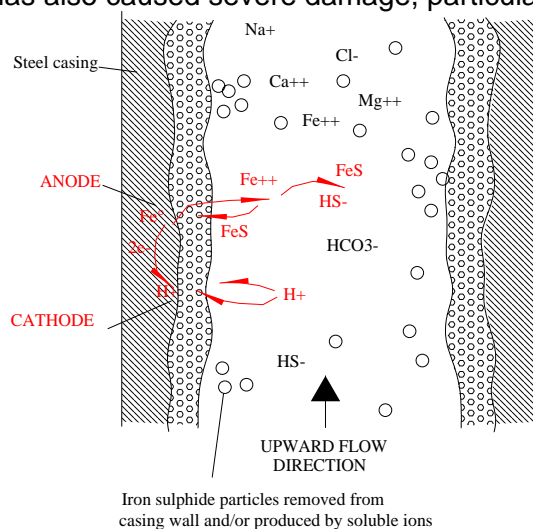
5. CHEMICAL INHIBITION STRATEGIES

Based on the assessment of damage source mechanisms, the design of a relevant chemical inhibition programme must clearly meet two requirements:

- fluid chemical treatment is to be initiated at the origin of the corrosion and/or scaling process, i.e. in most instances at bottom hole,
- inhibitor formulae are assigned two functions, namely (i) casing protection against corrosion, and (ii) inhibition of scale originating from the formation fluid and/or casing corrosion.

Most illustrations will refer to geothermal wells drilled in the Paris area to supply district heating networks.
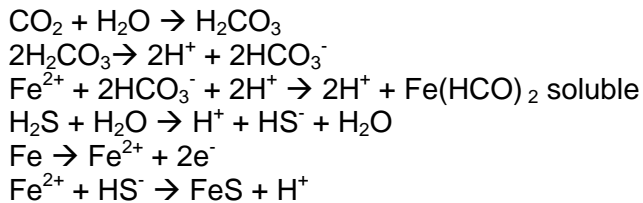
The geothermal setting addresses a carbonate reservoir produced in open hole via submersible, either electrically (induction motors) or hydraulically (turbine) driven pump sets. The brines are pumped, after cooling, via injection wells into the source reservoir. Wells are 2,000 m deep and deviated (35 to 55° inclination). The formation fluid exhibits high salinities (from 15 to 35 g/l eq. NaCl), pH's of 6 and a dissolved gas phase (GLR close to 0.15 m^3/m^3) enriched in CO_2, H_2S. Bottom hole temperatures and flow rates stand in the 55 to 85°C and 200 to 350 m3/h ranges respectively.

The damage process is characterized[4] by a continuous, quasi linear, and generalized corrosion caused by the combined action of dissolved CO_2 and H_2S in the saline, slightly acid and chemically reducing environment. It leads to the formation of iron sulphide deposits. Mackinawite is the dominant mineral species whose porous lattice crystal structure favours the continuity of the corrosion sequence summarized in fig. 3. Native iron sulphide can be an additional, minor though, scale contributor under depositional or suspended particulate forms. Microbiological corrosion by sulfate reducing bacteria has also caused severe damage, particularly on injector wells.
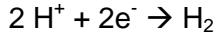

**Figure 3: Iron dissolution and sulphide precipitation process
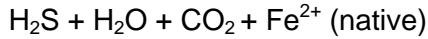in presence of aqueous H_2S and CO_2.**

Chemical reaction:

$$CO_2 + H_2O \rightarrow H_2CO_3$$
$$2H_2CO_3 \rightarrow 2H^+ + 2HCO_3^-$$
$$Fe^{2+} + 2HCO_3^- + 2H^+ \rightarrow 2H^+ + Fe(HCO)_2 \text{ soluble}$$
$$H_2S + H_2O \rightarrow H^+ + HS^- + H_2O$$
$$Fe \rightarrow Fe^{2+} + 2e^-$$
$$Fe^{2+} + HS^- \rightarrow FeS + H^+$$

Corrosion induced and native
$$2 H^+ + 2e^- \rightarrow H_2$$
for pH = 6
$$H_2S + H_2O + CO_2 + Fe^{2+} \text{ (native)}$$

5.1 Inhibition programmes

Several strategies may be contemplated to minimize corrosion/scaling induced damage, (i) pH reequilibration, (ii) partial (CO_2) pressure control, and (iii) chemical inhibition.

pH handling, could for instance, consist of injecting HCl to match the desired pH figure. A part from secondary effects unexpected before hand, it may prove, economically speaking, merely dissuasive. In particular the strong buffering impact of bicarbonates would require massive HCl consumptions to achieve a significant pH decrease.

CO_2 partial pressure control would either imply to reduce well discharge, install a submersible pump set in a self-flowing or flashing well or to inject CO_2 downhole.

Unless otherwise dictated by local, definetely site specific, conditions, chemical inhibition is the rule. Inhibition of $CaCO_3$ scale is most familiar to water treatment engineers. Threshold treatments (i.e. at low concentrations) of chemical additives, inorganic compounds such as phosphonates, have proved efficient in preventing precipitation of oversaturated $CaCO_3$. The same rationale can be extended to the treatment of other scale species (calcium, baryum and strontium, sulfates among others). As a matter of fact they do not suppress nucleation but instead slow down the germination process. This effect, known as crystal growth inhibition, can be also achieved by dispersants based on organic polymers, such as alkaline polyacrilates which are salts remaining stable in a wide temperature range and are environmentally safe (non toxic). They can significantly reduce crystal growth by blocking nucleation sites and preventing particle agregation. Combined phosphonate/polyacrylate formulations can demonstrate optimum efficiencies as the latter item adds dispersant properties to the former threshold/sequestering/chelating functions. Molecular weights (i.e. polymerised chains) are kept low in order to avoid flocculating/thickening shortcomings. These properties are discussed in more details in[4].

Surfactant filming agents based on fatty amins (octadecyclamins) belonging to the aromatic or aliphatic group are most popular in the oil industry. Their objective is to isolate the metal surface from the corrosive fluid by means of a supposingly monomolecular hydrophobic film, whose forming kinetics can be studied through sorption/desorption tests. These inhibitors can include biocides and oxygen scavengers (by addition of sodium sulfite or hydrazine for instance). Several formulations associate quaternary ammonia and a sequestering function in a hydroalcoholic solution which renders it totally water soluble.

At elevated concentrations the inhibitor exhibits biocide and detergent effects whereas at lower doses it demonstrates filming properties. Combined, custom designed, crystal growth inhibition and filming formulations can also be used. This was the rationale followed on selected Paris basin wells sensitive to both fluid corrosivity and scaling generated by precipitation of native (i.e. formation issued) and, corrosion generated, iron sulphide suspended particles.

Bacterial corrosion is another matter of concern, especially on injection wells and self-flowing systems degassing at production well head. Biocides are being implemented, in the framework of probative tests and protocoles[8], in batch mode including brief and massive (shock effect) injection cycles.

Agents combining biocide/corrosion inhibition properties have been experimented in this respect and substituted in several instances to initially injected either monofunctional corrosion or/and bifunctional corrosion/scaling inhibitors.

Candidate agents tested in the Paris area and other sites on low to medium temperature geothermal wells are listed in table 2 review sheet.

It is the author's opinion that the comprehension of inhibition mechanisms and efficient field applications remains widely experimental if not empirical and, by all means, site specific.

Nevertheless the impact of chemical inhibition as practiced on Paris basin wells is deemed positive and often cost effective.

Table 2: List of Selected Candidate Inhibitor Agents

Name	Function				Description
	Antiscale	Dispersant	Anticorrosion	Biocide	
SCI 1	X				Phosphonate non ionic
SCI 2		X			Low molecular weight polyacrylate anionic
SCI 3	X	X			Phosphonate/polyacrylate anionic
CORI 1			X		Cationic surfactants ; non ionic in glycol solutions
CORI 2			X		Fatty amin derivatives in aqueous solutions
BIOC 1				X	Non ionic surfactants and aldehydic derivatives
BIOC 2				X	Cationic surfactants and quaternary ammonia
BIOC 3				X	Superior aldehydes in aqueous solution
SCORI 1	X		X		Sequestering agents and fatty amin derivatives
SCORI 2	X	X	X		Phosphonate, polyacrylate and fatty amin derivatives
CORBIO 1			X	X	Non ionic surfactants and aldehydic derivatives
CORBIO 2			X	X	Fatty amin derivatives and quaternary ammonia
SCB 1		X	X	X	Polyacrylates, fatty amin derivatives, quarternary ammonia

6. TECHNOLOGY

6.1 Down hole chemical injection lines

The most reliable line developed to date, known as the AIT (auxiliary injection tubing)[6], has been implemented according to the following design criteria:
- line continuity as opposed to a threaded coupling tubing string,
- avoid down hole extraweight and well head hanging,
- accomodate three types of submersible, electric submersible (ESP), lineshaft (LSP) and hydraulic turbine (HTP), pump sets and subsequent annular restrictions,
- dissociation of pump and line handlings (running in hole, pulling out of hole),
- material definition and structure combining operational flexibility, stiffness and mechanical strength (burst pressure, tensile and yield strengths), chemical resistance (corrosion) and weight,
- compatibility with concentrated chemical inhibitors and formation fluids,
- permanent control of line integrity, thus avoiding costly and risky fishing operations,
- minimize induced pressure losses,
- five year lifetime under the conditions (artificial lift, high flowrates, deep deviated wells) prevailing in geothermal service.

Summing up, the AIT structure is that of a composite, slim, cylindrical and slick line combining steel materials and thermoplastics.

The candidate structures are depicted in figure 4 and in hole assemblies illustrated in figure 5 according to three artificial lift configurations. These lines, whose characteristics are listed in table 2, include (i) a central core (stainless steel injection tubing), (ii) four strengthening/integrity control wires, and (iii) two to three concentric thermoplastic/elastomer encapsulation selected, depending upon target service conditions, among the candidate materials whose properties are summarized in table 3.

The role of the strengthening wires is essential. They increase burst pressures and upgrade both line stiffness and flexibility during spooling/unspooling cycles on the coiled tubing reel. They also ease integrity control via electrical (insulation, resistivity) measurements. In addition the concept eliminates torsion torque during line extrusion, thus avoiding anti-giratory processes inherent to the manufacturing of standard electric cables.

The AIT bottom hole assembly includes (i) an insulating and seal clip connected to (ii) injection nozzles securing the diffusion in the formation water of a coherent jet of viscous inhibiting solutions, and (iii) a kick-off shank/sinking bar, occasionally centralized, easing string runs through

varying casing diameters (13"3/8 x 9"5/8 or 7"). In its upper part it is fixed, via a spool and stuffing box, to a pulley wheel, then connected to the surface injection system depicted in figure 5a.

Hybrid lines, designed in order to accomodate restricted annular clearance, utilize the flat pack AIT, connector and inflatable packer shown in figure 5c. Recently designed slim lines of the type represented in figure 4a and c avoid such line mixing and related connections.

Last but not least, AIT pressure losses are kept to a minimum (0.5 bar/1,000 m induced loss in 7" casings and 250 m3/h well discharge). Twenty such lines are routinely operating in Paris basin geothermal wells and several high to medium temperature lines are being tested in Turkey (Western Anatolia).
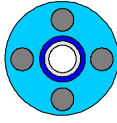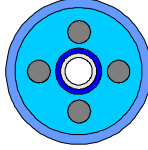

LOW TEMPERATURE SERVICE (<100°C)   HIGH TEMPERATURE SERVICE (>100°C)

	ID (mm)	OD (mm)	Material	ID (mm)	OD (mm)	Material	ID (mm)	OD (mm)	Material
Core injection tubing	6	8	SS	6	8	SS	4	6	SS, INCONEL
Internal encapsulation	8	10	PAII	8	10	PAII	6	8	PPS
Intermediate encapsulation					28	PP			
Outer encapsulation		25	PP	28	32	PA6/PP/EPDM		15	PPS

Figure 4: Typical downhole chemical injection lines (AIT types).
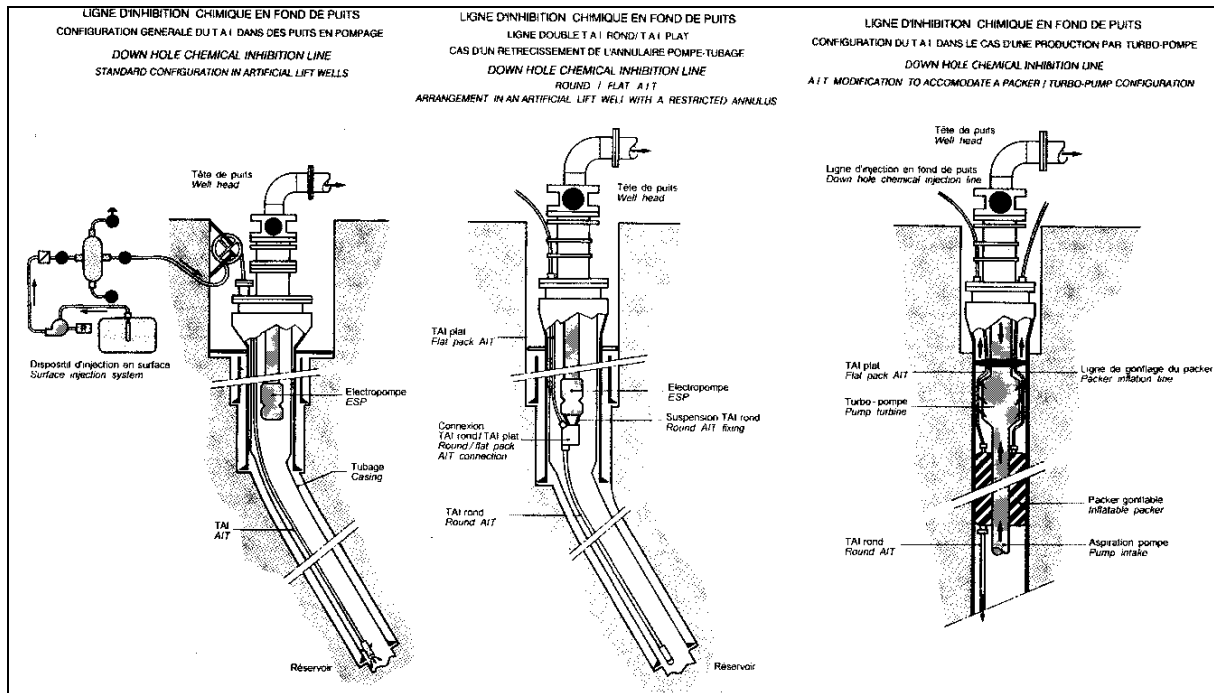

Figure 5: Downhole chemical inhibition lines/

Recent developments have added to the former chemical injection function the recording of bottomhole pressures and temperature thanks to a quartz gauge. This application is of utmost importance regarding the continuous monitoring, via a data transfer unit, microcomputers and a teleprocessing software, of reservoir and well performances as it allows for matching actual well losses to nominal values and performing periodical pressure build up tests and relevant calculations of reservoir and sandface parameters (transmissivity, skin factor).

Table 3: Candidate Thermoplastic and Elastomer Material Properties

Type de matériau (*) *Material type*	PPC	PA 11	PA 6	EPDM/ PP	PVDF	HALAR	PA 6/PP/ EPDM	PPS	TPFE	TPFA
Temp. de service max. (°C)	105	95	120	140	150	170	120	196	204	260

Max. operating temp. (°F)	*220*	*220*	*250*	*280*	*300*	*340*	*250*	*350*	*400*	*500*
Résistance à la traction (Mpa) *Tensile strength (Mpa)*	25	55	35	28	46	50	43	90	22	28
Elongation (%)	300	300	240	600	80	200	300	10	300	300
Module d'élasticité (Mpa) *Flex modulus (Mpa)*	1 200	1 000	760	347	2 700	1 700	1 980	750	655	625
Dureté *Hardness*	60 D	72 D	40 R	50 D	77 D	75 D	65 D	70 D	60 D	55 D
Absorption d'eau (%) *Water absorption (%)*	< 0,1	2,5	5	2	< 0,1	< 0,1	< 1	2,1	0	< 0,03

(*) PPC : Polypropylene Copolymer EPDM : Etylene Propylene Dyene Monomer TPFE : PolyTetraFluoroEthylene (Teflon)
PA 11 : Polyamide 11 HALAR : Chloro Tri Fluoro Ethylene TPFA : PerFluoro Alkoxy (Teflon)
PA 6 : Polyamide 6 PVDF : PolyVinyle Dyene Fluoride PPS : PolyPhenyl Sulphone

6.2   Surface injection system

The system sketched in figure 5a includes briefly (i) a high pressure volumetric, controlled rate, metering pump, (ii) a pulse dampening device, (iii) a back pressure, nitrogen fed, vessel preventing invasion of AIT by formation fluid, (iv) a no return valve, and (v) a regulation card adjusting inhibitor injected volumes to well discharge according to target concentrations.

7.   MONITORING

This is undoubtedly a vital segment of any chemical inhibition policy. It aims at (i) evaluating the efficiencies of selected candidate inhibiting agents, (ii) assessing optimum inhibitor concentrations, and (iii) matching the best possible cost/performance compromise.

Monitoring protocols usually involve the following headings :

- hydrodynamics : control of pressures and temperatures and subsequent well, reservoir, geothermal network and heat exchanger performances,
- fluid chemistry : general and topical (selected indicators, HS^-, $S^=$, Fe^{++}, Fe^{+++}, Ca^{++}, HCO_3^-, etc.) liquid and PVT (dissolved gas phase, GLR, bubble point) analyses,
- inhibitor injection concentrations : volume metering, flow concentrations via a tracing of the inhibitor active principle,
- solid particle monitoring : concentrations (staged millipore filtrations) and particle size diameters and distributions (optical counting, doppler laser velocimetry),
- microbiology : sulfate reducing bacteria numbering,
- corrosion : measurement of corrosion rates (coupons, corrosion meters),
- down hole line integrity : electrical measurements, pressurisation and/or tracer tests,
- periodical well logging inspection.

8.   CASE STUDIES

Selected cases relevant to Paris basin low temperature geothermal wells are exemplified in figures 6 to 10.

Figure 6 illustrates the impact of a combined scale/corrosion inhibitor on both suspended particle numbers and sizes which trend towards a significant decrease. Average values, prior and further to chemical inhibition, stand at 23,000/2.3 µm and 15,000/1.3 µm respectively. It should be emphasized in this respect that this trend may be regarded as initiated prior to inhibition proper which suggests that, on this particular site, a self immunizing mechanism could have built up as a consequence of indurated deposits acting as a protective coating. Nevertherless further indications (material balances via direct logging assessments) proved the inhibition programme to yield quite satisfactory results, in terms of casing integrity among others.

On a nearby location, the outcome of specific agents could be appraised thanks to long lasting coupon monitoring time series. Figure 7 clearly shows the modification of corrosion kinetics as a result of downhole chemical inhibition. Here corrosion rates (in the sense of coupon weight losses) have been reduced from the initial 300 µm/yr figure to less than 100 µm/yr. Of interest to note, particularly at injector well head, is that this trend could be boosted via the injection of a combined corrosion/biocide formulation substituted to the former single anticorrosion agent.
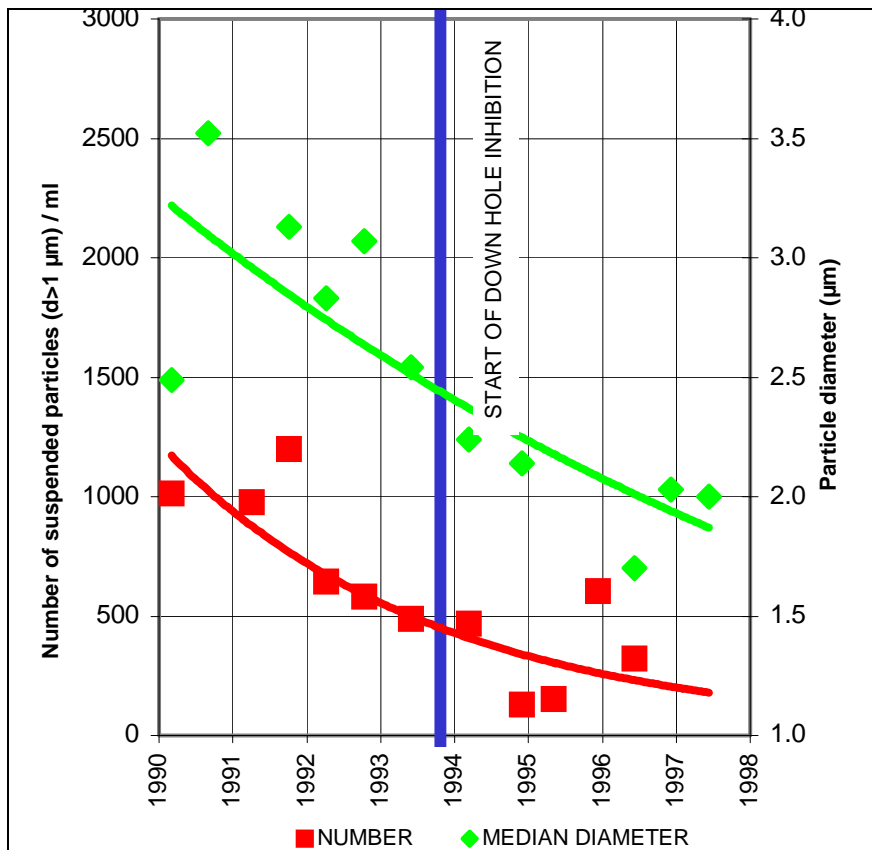
Figure 6: Suspended particiles monitoring. Geothermal doublet. Self-flowing well head.
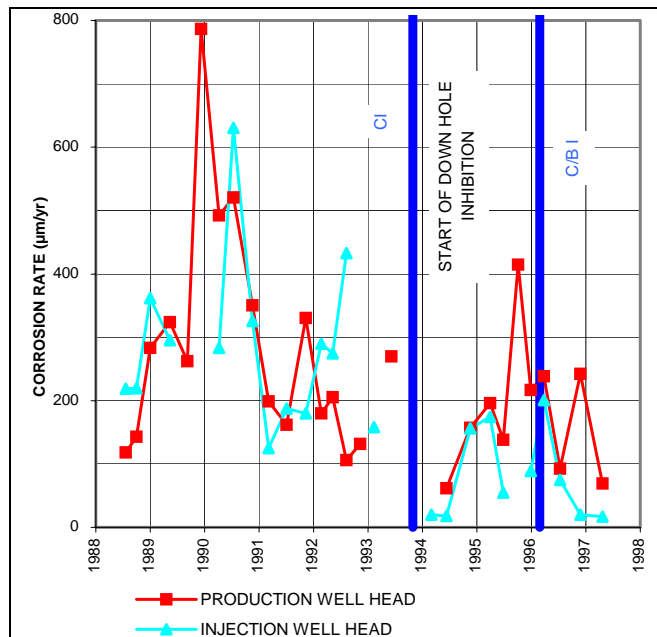

Figure 7: Corrosion rates measured on coupons. Self flowing production well.

Corrosion inhibition, in this geothermal context, is deemed efficient whenever total sulphides (i.e. sulphides proper + mercaptans) and iron (dissolved and total) concentrations exhibit sharp variations, i.e. increases and decreases respectively, as a consequence of inhibitor application. To simplify this means that the hydrophobic filming properties of the candidate agent keep acid gases (CO_2, H_2S) trapped in solution, thus preventing any interaction whatsoever with the casing metal lattice. This issue was clearly met on the example shown in figure 8. Implementation of a corrosion inhibitor has caused sulphide contents to rise from 4 to 9 ppm and iron concentrations to drop from2 to 0.2 ppm.
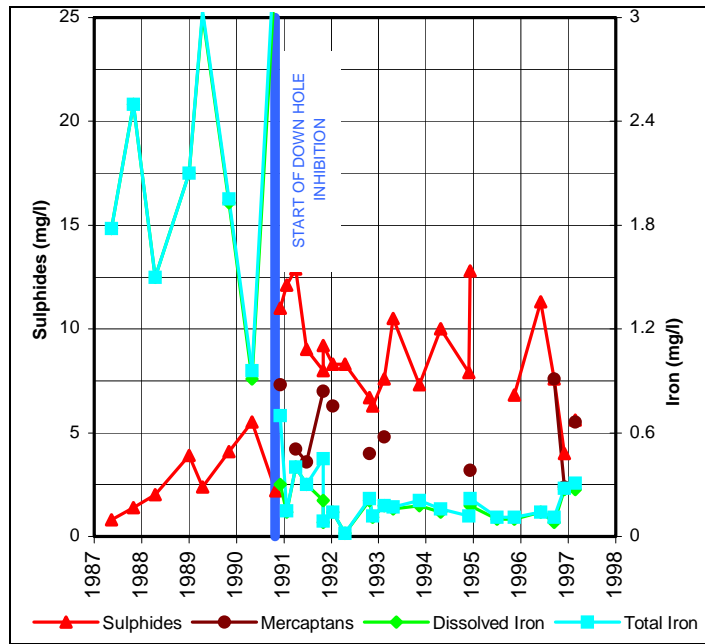
**Figure 8: Chemical monitoring of corrosion indicators.
Geothermal production well head.**

Checking filming/defilming (sorption/desorption) properties of corrosion inhibitors is another matter of concern. Those can be monitored via corrosion meters/recorders based on the polarization resistance principle in order to assess filming/defilming kinetics and related critical inhibitor doses and film remanence whenever injection ceases. These aspects are illustrate in figures 9 and 10.
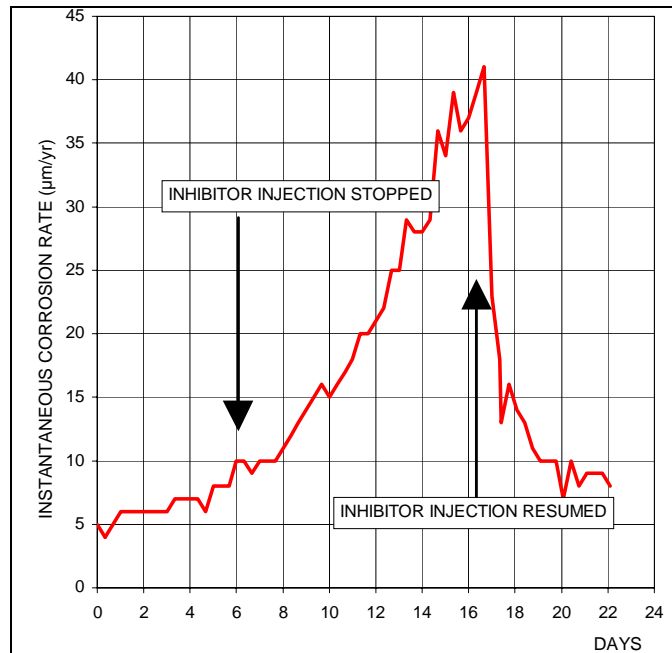
**Figure 9: Defilming (desorption) experiment of submersed metal surface.
Variation of instant corrosion rates.**

Preliminary investigations and simple thermochemical calculations can be exercised to design, and not a posteriori as often practiced by geothermal developers, adequate formulations. A typical scale assessment addressing a medium temperature carbonate field is summarized in table 4.

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Table 4: Scaling tendency of geothermal fluids

Fluid chemical composition (mg/l)					
Cations		Anions			
Na^+	310	Cl^-	160	TDS	1,480
K^+	30	HCO_3^-	620	pH	6.42
Ca^{++}	60	$CO_3^=$	0	Temperature	105°C
Mg^{++}	12	$SO_4^=$	180		
Ba^{++}, Sr^{++}	traces				
Fe^{++}	8				

Scaling tendencies			
$CaCO_3$		Sulfates	
Ionic strength	0.02	$CaSO_4$: precipitation unlikely	
Saturation pH	5.53	BaSO4, SrSO4 : no precipitation	
Langelier SI (pH 6.42)	0.88		
$CaCO_3$ supersaturation/precipitation potential : 130 g/m^3			
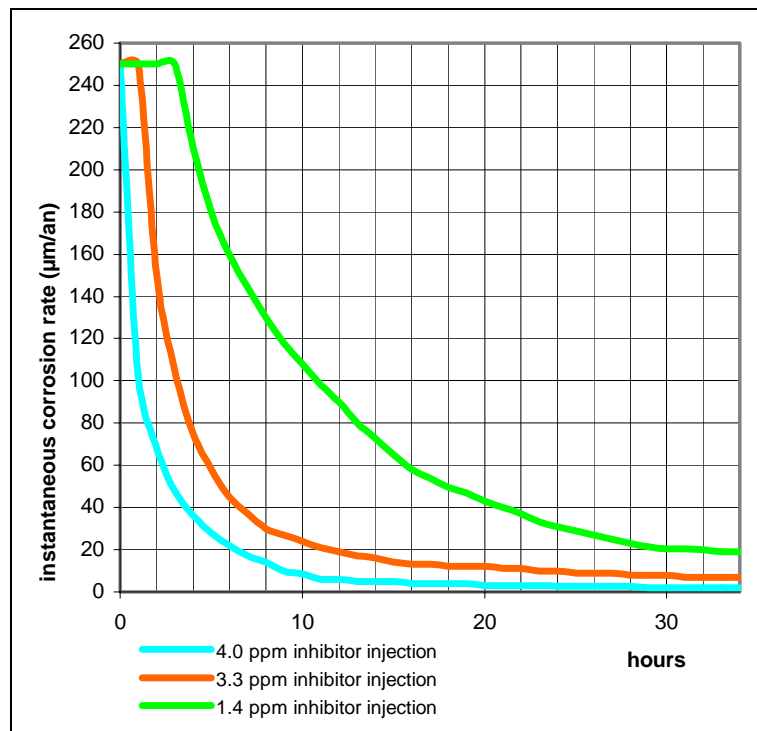
Figure 10 Corrosion inhibitor filming kinetics

9. ECONOMICS

The following developments, borrowed from a seven year practice of down hole chemical inhibition of geothermal district heating wells, are intended as a broad analysis, indicative of the cost patterns and trends and as a tentative appraisal of economic viability.

9.1 Costs

(i) Investments (CI)
- well rehabilitation (workover) costs prior to implementing chemical inhibition proper,
- chemical injection equipment : surface injection system, down hole injection line, well head modifications,
- monitoring equipment : coupon holders, corrosion probes, measuring/recording devices, sampling ports,
- installation costs,
- engineering fees,
- exploitation losses incurred as a result of plant shut down (1 month summer regime).

(ii) Operation/maintenance costs (OMC)
- monitoring,

- equipment maintenance and renewal,
- consumables (chemicals),
- miscellaneous costs (insurance, contingencies).

9.2 Viability
The worst (A) and best (B) case figures are outlined in table 5.

Table 5: Chemical inhibition cost breakdown

	Case A	Case B
Nominal discharge rate (m^3/h)	150	350
Geothermal yearly heat supply (MWht)	25,000	54,000
Inhibitor concentration (mg/l)	3.5	2.5
Investment costs (10^3 €)	490	430
Operation/maintenance costs (10^3 €/yr)............	50	45
Heat gains (MWh$_t$/yr)	6,500	8,000
Additional revenues (10^3 €/yr)..........................	150	300

Investment costs are to be reiterated entirely every five years, indeed a conservative assumption. Inhibitor concentrations vary, from 2 to 5 mg/l, throughout the year. Well impairment is estimated between 10 and 25 % of the nominal (i.e. non damaged well) yearly heat supply.

Therefore chemical inhibition is considered as achieving economic viability when, in constant non discounted terms, additional revenues (REV) exceed yearly expenditure (annuity and OM costs), thus verifying REV > [(CI / 5) + OMC].

It can be seen that case A does not match this feasibility threshold. On the contrary, case B displays far more attractive trends with a non discounted pay back time of ca. two years.

However these more optimistic figures trend less favourably when considering that, in absolute terms, they should be added to initial doublet expenditure in which case they turn into a penalty and not as an asset instead.

This aspect had clearly been overlooked in early geothermal district heating design and feasibility assessment stages.

10. CONCLUSIONS
Exploitation of low grade geothermal heat often addresses thermochemically sensitive fluid environments resulting in severe well impairment and, occasionally, in irreparable damage.

Such adverse fluid settings and damage have been experienced while developing large geothermal district heating systems in the Paris area. Clearly, as in many reported case histories, these aspects, not known beforehand, had been overlooked in the early design and development stages.

Damage diagnosis and prediction of fluid corrosion and scaling tendencies have enabled to assess, *a posteriori*, adequate removal and preventing procedures. The latter led to the implementation of relevant material definition and chemical inhibition designs based on removable fibre glass/ epoxy resin well lining and down hole injection of corrosion/scaling inhibitors and biocides.

Of particular significance is the reliability demonstrated by down hole chemical inhibition and reservoir control lines. This strategy, backed by sound efficiency monitoring of candidate filming corrosion inhibitors of the fatty amin type and of combined phosphonate and alkaline polyacrylate scale inhibitors, proved rewarding so far and cost effective in safeguarding well life and restoring close to nominal target production ratings.

Similar policies and technologies could, despite the site specificity of chemical inhibition, be extended, preferably at design stage, to selected low temperature geothermal development prospects

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