THERMOCHEMICALLY DRIVEN GAS–DYNAMIC FRACTURING (TDGF)

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Disclaimer

Abstract

This report concerns efforts to increase oil well productivity and efficiency via a method of heating the oil-bearing rock of the well, a technique known as Thermochemical Gas-Dynamic Fracturing (TGDF). The technique uses either a chemical reaction or a combustion event to raise the temperature of the rock of the well, thereby increasing oil velocity, and oil pumping rate. Such technology has shown promise for future application to both older wellheads and also new sites.

The need for such technologies in the oil extraction field, along with the merits of the TGDF technology is examined in Chapter 1. The theoretical basis underpinning applications of TGDF is explained in Chapter 2. It is shown that productivity of depleted well can be increased by one order of magnitude after heating a reservoir region of radius 15-20 m around the well by 100 degrees 1-2 times per year. Two variants of thermal stimulation are considered: uniform heating and optimal temperature distribution in the formation region around the perforation zone. It is demonstrated that the well productivity attained by using equal amounts of thermal energy is higher by a factor of 3 to 4 in the case of optimal temperature distribution as compared to uniform distribution.

Following this theoretical basis, two practical approaches to applying TDGF are considered. Chapter 3 looks at the use of chemical intiators to raise the rock temperature in the well via an exothermic chemical reaction. The requirements for such a delivery device are discussed, and several novel fuel-oxidizing mixtures (FOM) are investigated in

conditions simulating those at oil-extracting depths. Such FOM mixtures, particularly ones containing nitric acid and a chemical initiator, are shown to dramatically increase the temperature of the oil-bearing rock, and thus the productivity of the well. Such tests are substantiated by preliminary fieldwork in Russian oil fields.

A second, more cost effective approach to TGDF is considered in Chapter 4: use of diesel-fuel to raise the rock temperature by a combustion process in the well. The requirements for such a Gas-Vapor Generator are laid out, and the development of a prototype machine is explained. This is backed up with laboratory experiments showing that the fuel-water mixture used does significantly increase the viscosity of the oil samples. The prototype Gas-Vapor Generator is shown to be able to operate at temperatures of 240 ℃ and pressures of 200 atm. Unfortunately, geopolitical and economic factors outside of our control led to the cancellation of the project before the field testing phase of the generator could be commenced. Nevertheless, it is to be hoped that this report demonstrates both the feasibility and desirability of the Gas-Vapor Generator approach to the application of TDGF technology in both existing and new wells, and provides a foundation for further research in the future.

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Nomenclature

C_P	volumetric specific heat capacity of rock matrix
C_P^{oil}	specific heat capacity of oil
E	total heat input to oil-bearing rock within annular volume
I	fluid conductivity
L	pay zone thickness, m
M	mass of oil extracted, kg
P	pressure, Pa
Q	well productivity, $m^3.s^{-1}$
T	temperature, K
T_0	background temperature, K
U	Darcy flux, $m.s^{-1}$
$V(^*)$	volume, m^3
ΔT	temperature rise over background temperature, K

α porosity, dimensionless

χ thermal diffusivity

γ fluid weight per unit volume of rock matrix

κ heat conducitivity of rock

μ dynamic viscosity, $Pa.s$ or $poise$

ρ density, $kg.m^{-3}$

ρ_{oil} oil density, $kg.m^{-3}$

$\tau_{1/2}$ time (half–life), s

d coefficient of permeability, D or cm^2

k pore fluid conductivity

r wellbore radius, m

Roman Symbols

a excess air factor, dimensionless

CT cyclic treatment

FOM fuel–oxidizing mixture

PT pulse treatment

VT vibration treatment

WV working-fluid volume, m^3

TDGF Thermochemically Driven Gas–dynamic Fracturing

CHAPTER 1

Background and introduction

1.1 Enhancing oil recovery rates

In partially depleted oil reservoirs, hundreds of thousands of wells produce oil at low rates. The costs of stimulation the rate of oil recovery may not be covered by the existing revenues. Therefore, inexpensive new treatment technologies are required. Furthermore, the global oil reserves include about 50% of high-viscosity and bitumen oil. Its extraction is impeded by high costs. Specialists predict that the relative amount of high-viscosity oil gained in situ in 10 to 15 years may reach 50% in some countries.

The decrease in the productivity and cost-effectiveness of an oil well is explained, in part, by the accumulation of highly viscous oil deposited on the surface of pores and cracks in the near-borehole zone of the pay. This process takes place in the vicinity of any borehole in conventional and heavy/viscous-oil reservoirs. The inflow of oil is blocked by these deposits, which are difficult to remove without heating.

1.2 Hydraulic fracturing

The most effective current method for stimulating oil wells is the (physical) technology of hydraulic fracturing developed in the USA. In hydraulic fracturing, a working fluid (oil, water, or carbon dioxide) is pumped down a well under high pressure to fracture a pay and create cracks of large length and volume. Typically, the hydraulic fracturing working-fluid volume (WV) is about 10-20 cubic meters. The pumps which are on the surface, create cracks, increase their volume and ramified area inside a layer until the system is dynamically balanced, after which the growth of cracks stops. All pumped liquid leaves through lateral surfaces of new cracks in a layer.

The hydraulic well-stimulation methods currently used to enhance oil production are very efficient, but may be further improved. In commonly deployed hydraulic fracturing technology, the work done to create fractures is provided by a fluid-injection system with a pumping power of up to 5,000 hp. In terms of efficiency, this may be compared to the use of a fuel pump as the only source of energy for rotating the wheels of a car without combustion of fuel, *i.e.* powerful pumps are required in order to introduce the inert liquid into a well. A better solution is to find an economical system to introduce fuel and an oxidizer using precise binary mixes, via a machine capable of directing their reaction. Such binary mixtures combust when combined, which has a beneficial effect upon the rate of oil recover. This is known as Thermochemically Driven Gas dynamic Fracturing (TDGF) technology.

1.3 Thermochemically Driven Gas dynamic Fracturing (TDGF) technology

In the controlled Thermochemically Driven Gas dynamic Fracturing (TDGF) technology developed by More Oil, high-temperature foaming reacting agents are injected into a pay instead of an inert fluid. A special apparatus has been constructed to increase the working volume (WV) of the foaming agents introduced into a well compared to a typical hydraulic fracturing WV. The TDGF technology provides an efficient solution to this problem as it combines heating of oil by chemical reaction with formation of new cracks.

The TDGF technology is an effort to dramatically improve on the current technology of hydraulic fracturing by combining the fracturing capabilities of the latter with the benefits of thermally heating the well. This is achieved by pumping a large volume of gas and liquid chemical reagents into a formation, warming the formation via high-pressure combustion, and increasing oil production.

Thermal technologies are receiving increasing attention as methods for increasing oil extraction, creating thoroughgoing changes in traditional schemes of oil production while being commercially viable. For example, Canada, who during recent years successfully regenerated an older method of heating bituminous layers with steam, uses a technology that burns part of produced carbohydrates (15-20%) to markedly speed the extraction of the remainder.

TDGF is a multistage treatment:

- Vibration-treatment stage, which entails fracturing driven by vibration combustion.
- Pulse-treatment stage, which involves expanding cracks caused by the gas produced in a continuing chemical reaction.
- Cyclic-treatment stage, which causes further expansion by high-temperature, foaming reacting agents.

Documented increases in the permeability of formations treated with the gases released by the chemical reactions used in the TDGF technology suggest that a solution to the problem of thermochemical stimulation can be found through a drastic increase in the amount of hot gas introduced into the pay zone. The entire low-permeability zone can be heated so that the heaviest fractions around the wellbore (also known as the stagnation zone) will be removed.

Calculations and results of the works at four wells, which were heated with chemicals, convinced More Oil that at fields with usual oil it becomes immensely profitable to pump the heat into the productive layer if we heat a big amount of rock (not less than 15 thousand tons) not less than up to 100 ℃. The mode of cracking and heating of the productive layer that will guarantee the increase of oil flow rate up to 10-15 times was calculated. This maintains a rapid rate of production (as in Canada) until almost the end of the oil at that field. In such case, it would take about 2 years to empty a medium field. The amount of not extracted oil should minimize in 2 - 3 times by our estimation. With this technology, to keep a high speed of oil production, it is necessary to make cracking and heating of the layer immediately after a new well has begun to operate, and then repeat the operation every 1 - 2 years at fields with usual and heavy oil.

These calculations were verified in laboratory conditions by applying chemicals at core samples containing oil. Experiments proved that heating of the reservoir with usual oil up to 100 ℃ will decrease thickness of the oil 10 - 20 fold.

1.4 Project goals

The overall initial goal of the project was to build, test, and field demonstrate a Chemical Generator using the TDGF technology on a sample of oil wells. In the course of a TDGF treatment, high-temperature foaming agents produced by a liquid-phase reaction would be injected into a pay zone instead of an inert fluid.

An advanced version of the TDGF technology was envisaged, where introduction of chemical reagents into the well would be automated. The diagnostic gas generator and automatic chemical supply system were planned to be constructed under subcontracts with two Russian companies. The final system was planned for field tests in U.S. wells.

The technology has the potential to become a supremely valuable for the oil business in particular. Every model of oil production shows a significant increase in the production of oil as heat is provided to the reservoir. The TDGF technology will combine the power of hydraulic fracturing with the heating capabilities of the thermal process.

This report covers a summary of the TGDF process followed over the course of this project. The theoretical background behind TGDF is set out in Chapter 2. Following this, two approaches to achieving TGDF are discussed: firstly, a chemical generator approach (Chapter 3), and following further cost analysis, a diesel-fuel gas generator which was the focus of the major part of the project (Chapter 4). While final deployment of this generator could not be accomplished by the end of the project timescale (owing to several geopolitical factors out of the control of the participants), the theoretical and testing work undertaken during the course of the project will lay a solid foundation for further TGDF technologies in the future.

CHAPTER 2

Theoretical background:
Heating the Depleted Well Vicinity to Enhance Oil Output

2.1 Introduction

This chapter outlines the theoretical basis behind the TDGF technology via the modeling of well productivity and oil viscosity dependence upon temperature, and other associated factors.

2.2 Modeling the thermal stimulation of oil-bearing formations

Large-scale thermal stimulation of an oil-bearing formation in the perforation zone is a promising method for increasing well productivity. In this method, the formation temperature is raised by about 100 K or higher within a radial distance of several tens of meters from the wellbore. Practical implementations of large-scale thermal stimulation require substantial energy input. Therefore, preliminary theoretical estimates and calculations should be performed with a view to minimizing the energy input depending on the formation characteristics and well operating parameters. Previous literature has not tackled this problem, rather focusing on processes in the vicinity of the borehole [1] and thermal stimulation of reservoirs [2].

To determine the dependence of well productivity on relevant parameters, such as oil viscosity, consider the flow regime in the pseudo-steady state attained after the leading edge of a cylindrically symmetric thermal disturbance (heating wave) propagating through rock from the perforated zone of a wellbore of radius r_1 has stopped at $r = r_2$. Further propagation may be impossible due to the effect of neighboring producing wells or the finite horizontal extent of the pay.

The cylindrically symmetric approximation is valid when the perforation interval coincides with the pay-zone thickness L.

The boundary conditions are set by specifying the pressure values P_1 and P_2 at r_1 and r_2, respectively. These values slowly vary with production time, depending on the horizontal extent of the pay. The analysis that follows is restricted to relatively short time intervals, and both P_1 and P_2 are treated as constant parameters.

2.3 Darcy Equation

According to linear Darcy's law [1, 2], the Darcy flux U (volumetric flow rate per unit area in a porous medium) is proportional to the gradient of pressure P divided by the dynamic viscosity μ:

$$U = (d/\mu) gradP \tag{2.1}$$

The CGS unit of dynamic viscosity is the poise (P), and the permeability d (related to porosity and pore morphology) is measured in darcys ($1\ D = 1\ cm^2$). Equation 2.1 between Darcy flux and pressure gradient can alternatively be written as

$$U = (K/\gamma) gradP \tag{2.2}$$

where γ is the weight of fluid per unit volume of the rock matrix, and the pore fluid conductivity K is related to permeability as

$$K = (\gamma/\mu)d \tag{2.3}$$

2.4 Pseudo-Steady-State Well Operation: Productivity Dependence on Oil Viscosity and Other Parameters

To find the dependence of the productivity Q on P_1, P_2, r_1, and r_2, note that it equals the radial flow rate across the cylindrical surface of area $2rL$ in a pseudo-steady-state regime:

$$Q = 2\pi rLU \tag{2.4}$$

Substituting the expression 2.4 for U into 2.1, integrating the resulting equation, and assuming that the ratio μ/d is independent of r, we obtain

$$P(r) = (Q/2\pi L)(\mu/d)ln(r_2/r_1) + const. \tag{2.5}$$

The unknown integration constant and Q are determined by using the boundary conditions $P(r_1) = P_1$ and $P(r_2) = P_2$. As a result, we have $const. = P_1$ and

$$Q = 2\pi L(d/\mu)(P_2 - P_1)/ln(r_2/r_1) \tag{2.6}$$

(A formula analogous to 2.6 was given in [1]. Recall that Q is the fluid volume extracted from the well per unit time.) If all quantities on the right-hand side of 2.6 are expressed in CGS units, then Q will be measured in cm^3/s. This numerical value of Q will remain invariant if permeability and pressure are measured in darcys and atmospheres, respectively. An example of calculation of Q is given below. However, the following important observation must be made about the time variation of any quantity characterizing the well operating conditions and the thermally disturbed pay. Since time enters the governing equations only through the ratio t/μ, the solution corresponding to a particular value of dynamic viscosity can easily be rescaled in time to obtain the solution for another value of μ. In particular, it is clear from 2.6 that Q is inversely proportional to μ. This scaling property can be used to determine the change in productivity caused by thermal stimulation of the surrounding pay zone. When the initial temperature is relatively low, the viscosity of oil is drastically reduced by heating (e.g., for an oil with density 0.96 g/cm^3, viscosity decreases from approximately 400 to 25 cP as the temperature rises from 40 to 100 ℃ [1]). When the temperature field in a nonuniformly heated region is known, the value of Q can be calculated as a one-dimensional integral over r (see below).

The value of Q given by 2.6 increases with decreasing viscosity.

The temperature dependence of the ratio μ/d is dominated by the steep decrease in oil viscosity with increasing temperature, since d is a slowly varying function of temperature. To facilitate further calculations, the graphic representations given in [1] for the density dependence of the viscosity of a gas-free oil at 15.15 ℃ and 13.6 ℃ and a pressure of 1 atm were used along with its temperature dependence to obtain an interpolation formula valid for oil of density 0.96 g/cm^3:

$$\mu = Aexp(B/T);\ A = 2.625 \times 10^{-7} P,\ B = 5135 K \tag{2.7}$$

Because of the exponential form of 2.7, even a relatively small temperature rise in the oil-bearing formation will lead to a substantial increase in Q. This behavior of oil viscosity underlies the improvement of well productivity by thermal stimulation.

If μ/d varies with r, then analytical expressions analogous to 2.5 and 2.6 cannot be obtained by direct integration. However, the results can be written in quadratures:

$$P_2 - P_1 = (Q/2\pi L)I;\ Q = 2\pi .L(P_2 - P_1)/I \tag{2.8}$$

where

$$I \equiv \int_{r_1}^{r_2} (\mu/d) r^{-1}\, dr \tag{2.9}$$

Integral 2.9 can be calculated if μ/d is known as a function of r (see next section).

2.5 Well Productivity Dependence on Temperature Distribution for a Given Total Thermal Energy Input

The total heat input to the oil-bearing rock occupying the annular volume within $r_1 \le r \le r_2$ is related to the temperature distribution as follows:

$$E = 2\pi L C_P \int_{r_1}^{r_2} \Delta T(r).r\, dr \tag{2.10}$$

where

$$\Delta T(r) = T(r) - T_0 \tag{2.11}$$

is the temperature rise over the background temperature T_0 and the volumetric specific heat C_P of the rock matrix is assumed to be temperature independent. Temperature dependence of specific heat may be taken into account in 2.10 by replacing $C_P \Delta T$ in 2.10 with $\int_{T_0}^{T_0+\Delta T} C_P\, dT$.

Each particular value of E corresponds to infinitely many functions $T(r)$ satisfying 2.10. Each function corresponds to a certain viscosity distribution and a certain value of Q. Formally, a solution to this variational problem is determined by imposing an additional constraint. However, it can easily be solved when the maximum value of Q is sought. Here, particular solutions are found corresponding to the maximum attainable Q and a uniform temperature rise ($\Delta T = const.$).

In the case of a uniform temperature rise, the well productivities calculated for $\Delta T = 0$ and 100 K were compared. Specifically, the following parameters were set: $P_2 - P_1 = 20$ atm, L = 20 m, r_1= 0.2 m, r_2 = 40 m, T0 = 300 K, and $d = 0.001$ D. According to 2.7, $\mu = 7.13$ and 0.099 P at 300 and 400 K, respectively. For these values of parameters, expression 2.6 yields $Q = 13.3$ cm^3/s = 115 m^3/day without thermal stimulation and $Q = 961$ cm^3/s = 83 m^3/day for $\Delta T = 100K$ (72 times higher).

Drawing an analogy between electrical and fluid conductivity, the annular regions with thickness dr and area $2\pi r$ per unit wellbore length were considered as series-connected conductors with conductance $2\pi r/\mu(r)$ making up an electric circuit. The critical region responsible for the dominant contribution to the value of Q has the lowest conductance. When ΔT is independent of r and $\mu(r) = const$, the critical coordinate is $r = r_1$. In the case of an arbitrary temperature distribution, the critical point can be located anywhere. However, it is obvious that the highest total conductance (lowest resistance) is attained when the circuit has no critical point at all. This condition corresponds to linear variation of viscosity with radius:

$$\mu/r = const. \tag{2.12}$$

Calculating integral 2.9,

$$I = d^{-1}\mu_1 r_1^{-1}(r_2 - r_1) \equiv d^{-1}\mu_2 r_2^{-1}(r_2 - r_1) \tag{2.13}$$

is obtained.

Substituting I from 2.13 into the latter expression in 2.8 yields

$$Q = 2\pi L r_1 d(P_2 - P_1)/[\mu_1(r_2 - r_1)] \tag{2.14}$$

To relate the heat input E to Q, μ_1 is required (or, equivalently, μ_2). Solving 2.7 for T,

$$T = B/ln(\mu/A)K \tag{2.15}$$

combine 2.15 with 2.11 to express ΔT in terms of μ and then use 2.12 to rewrite the result as a function of r:

$$\Delta T(r) = B/[ln(\mu_2/A) + ln(r/r_2)] - T_0 \tag{2.16}$$

By virtue of condition 2.15 applied to the point indexed by 2,

$$\Delta T(r) = B/[B/T_2 + ln(r/r_2)] - T_0 \tag{2.17}$$

is obtained.

Substituting $\Delta T(r)$ given by 2.17 into 2.10, a relation between the total heat input E and T_2 is obtained:

$$E = 2\pi L C_P \int_{T_1}^{T_2} B/[B/T_2 + ln(r/r_2)] - T_0 r\, dr \tag{2.18}$$

For a given value of E, it is a transcendental equation for the parameter T_2 in the integrand. Equation 2.18 is easy to compute by iteration. Below, its solution for $E/C_P = 100\pi L(r_2^2 - r_1^2)Km^3 = 2.01107Km^3$ is given. (In the case of a uniform thermal disturbance, this value of E/C_P corresponds to a temperature rise of 100 K in the entire domain of volume $\pi L(r_2^2 - r_1^2)$. Calculating T_2 for $r_1 = 0.2$ m, $r_2 = 40$ m, $T_0 = 300$ K, $A = 2.625 \times 10^{-7}P$, and $B = 5135K$,the following are obtained: $T_2 = 384.4K$, $\mu_2 = 0.166P$, $\mu_1 = 8.3110 - 4P$, and $T_1 = 637K$. The following are the resulting distributions of $\mu(r)$ and $T(r)$:

$$\mu(r) = 0.166(r/r_2)P,\ T(r) = B/ln[\mu(r)/A] \tag{2.19}$$

The well productivity given by expression 2.14 with $\mu_1 = 8.3110 - 4P$ is

$$Q1 = 2\pi L r_1 d(P_2 - P_1)/[\mu_1(r_2 - r_1)] \tag{2.20}$$

It follows from 2.6 and 2.20 that

$$Q1/Q = [r_2/(r_2 - r_1)](\mu/\mu_2)ln(r_2/r_1) \tag{2.21}$$

where $\mu = 0.099P$ (see above). Note that ratio 2.21 is independent of the pressure drop $P_2 - P_1$ and conductivity K. For $\mu_2 = 0.166P$, expression 2.21 yields

$$Q1/Q = 3.16 \tag{2.22}$$

It can be seen that the productivity can be increased by a factor of 3 for the same preset value of the total heat input E by optimizing the temperature distribution. This result is obtained by assuming cylindrical symmetry, which is justified in the case of a relatively small pay-zone thickness. Calculations performed for formations with larger pay-zone thicknesses by using an analogous spherical model yield $Q1/Q \approx 4$. Substituting $d = 0.001D$, $P_2 - P_1 = 20$ atm, $r_1 = 20$ cm, $r_2 =$ 4000 cm, and $\mu_2 = 0.166\,P$ into 2.20 yields

$$Q1 = 3030\,cm^3/s = 262\,m^3/day \tag{2.23}$$

For the uniform temperature rise considered above, Q = 83 m^3/day (see above). As expected, the ratio 262/83 agrees with 2.22 [4]. The optimal temperature distribution found here is of interest with regard to low-porosity oil-bearing formations, where the injected heat is mostly absorbed by the solid rock matrix and is therefore retained for a relatively long time. In the case of a highly porous rock, the temperature distribution rapidly decays as the heated oil is extracted.

2.6 Relaxation of a Thermally Stimulated Reservoir and Dependence of Well Productivity on the Cooling Regime

A thermally stimulated pay zone (or a region including the pay zone and surrounding barren rock) cools down via two mechanisms of heat transfer: heat conduction and thermal convection. The former means diffusion of heat to the periphery. The latter means heat transfer by oil percolating through the non-uniformly heated formation to a producing well. Oil that flows to the wellbore from the unheated periphery draws heat from the stimulated zone and is then extracted. A numerical technique has been developed for simulating these processes, which can be used to calculate the cooldown time for a thermally stimulated pay for given initial parameters, including the amount of heat injected into the formation, the heated volume, the specific heat and heat conductivity of the oil-bearing rock, the temperature-dependent oil viscosity, the starting productivity of the well that has been thermally and hydraulically stimulated by using our technology, and other parameters.

In addition to detailed computations, simple approximate formulae to estimate the relation between well productivity, cooldown time, heated-volume size, and other characteristics were used. As examples, the cooldown times for shut-in and producing wells were estimated. In the case of a shut-in well, the cooling is controlled by conductive heat transfer.

2.6.1 Conductive Cooling of a Thermally Stimulated Pay Zone

Suppose that the thermally stimulated zone is a cylinder of volume $V^* = 2\pi r^3$ with radius r and height $2r$, coaxial with the casing. When heat is injected into the pay in the vicinity of the borehole, the starting temperature rise must decay from the heat source toward the periphery. This nonuniform temperature distribution is simulated in detailed computations. However, these estimates are obtained for a zone uniformly heated from the background temperature T_0 to a given temperature T^*, e.g., to $T^* = T_0 + 100K$. The volume of the zone is determined by the heat input E and $(\Delta T)^* = T^* - T_0$:

$$V^* = E/C_P^{vol}(\Delta T)^*. \tag{2.24}$$

The specific heat C_P^{vol} per unit volume of the two-phase medium (oil-bearing porous rock) is

$$C_P^{vol} = C_P\rho(1-\alpha) + C_P^{oil}\rho_{oil}\alpha \tag{2.25}$$

where C_P and ρ are the specific heat and density of silica, C_P^{oil} and ρ_{oil} are the specific heat and density of oil, and α is porosity defined as the volume of the pore space divided by the total volume.

For a shut-in well, the time $\tau_{1/2}$ required for the temperature rise to drop from ΔT to $\Delta T/2$ (e.g., from 100 K to 50 K) can be approximately expressed as

$$\tau_{1/2} = 0.13^{2/3} r^2/\chi \tag{2.26}$$

where χ is thermal diffusivity, i.e., the ratio of heat conductivity κ of the rock to its volumetric specific heat at constant pressure (density multiplied by specific heat at constant pressure). To evaluate the cooldown time, the value of χ in 2.26 can be taken for porous silica of density 2.22 g/cm^3. At 300 and 500 K, the thermal conductivity of dense sandstone is close to that of polycrystalline silica: 1.36 and 1.63 W/mK, respectively [3]. Using linear interpolation, the thermal conductivity was shown to be 1.5 W/mK at 400 K. For porous silica, we have $\kappa_p = \kappa\rho_p/\rho$. The specific heat of silica at 400 K is 53.4 J/molK. Hence, its thermal diffusivity at 400 K is

$$\chi = \kappa_p/\rho_p C_P = \kappa/\rho C_P \approx 6.4 \times 10^{-3} cm^2/s \tag{2.27}$$

(Note that thermal diffusivity is independent of porosity in the low-porosity limit, since both thermal conductivity and volumetric specific heat are proportional to density.) Combining 2.26 with 2.27 , we obtain

$$\tau_{1/2} \approx 3.76 r_m^2 \, days \tag{2.28}$$

where r_m is the radius r measured in meters, For $r_m = 5$ and 10, formula 2.28 yields 94 and 380 days, respectively.

2.6.2 Convective Cooling of a Thermally Stimulated Pay Zone

Before the conductive and convective contributions to heat transfer were compared, the cooldown time was estimated by neglecting the former. In the case of a quasi-steady Darcy flux, the rate of extraction of heated oil equals the flow rate of unheated oil coming from the periphery, and the mean temperature of the heated zone satisfies the energy balance equation

$$C_P^{oil}(T - T_0)dM/dt = V^* C_P^{vol} dT/dt \tag{2.29}$$

which entails

$$dT/(T - T_0) = [C_P^{oil}/V^* C_P^{vol}]dM \tag{2.30}$$

where M is the mass of oil extracted over the time elapsed after stimulation.

Integrating Eq. 2.30 subject to the initial condition $T = T^*$ at $t = 0$,

$$T - T_0 = (\Delta T)^* exp(-\lambda M) \tag{2.31}$$

$$\lambda = C_P^{oil}/V^* C_P^{vol} \tag{2.32}$$

Suppose that the temperature rise in the pay zone has dropped by half: $T - T_0 = (\Delta T)^*/2$. Then, it follows from 2.31 that

$$M = ln2/\lambda \tag{2.33}$$

Substituting the values of specific heat and density for silica and oil [3], $C_P = 0.89J/gK$, $C_P^{oil} = 2.10J/gK$, $\rho = 2.65g/cm^3$, and $\rho^{oil} = 0.73 - 0.94g/cm^3$, into 2.25 and 2.32 and setting $\alpha = 0.2$ and $V^* = 2\pi r^3$,

$$1/\lambda = (6.56 - 6.83)r_m^3\, tonnes$$

Then, 2.33 yields

$$M = (4.5 - 4.7)r_m^3\, tonnes \tag{2.34}$$

For oil with an average density of 0.8 g/cm^3,

$$M = 4.6r_m^3\, tonnes \tag{2.35}$$

For $r_m = 5$ and 10,

$$M = 575\, tonnes\, and\, 4600\, tonnes \tag{2.36}$$

respectively. Assuming constant daily production,

$$M = mt_d$$

where m is daily production and t_d is the production period measured in days. If $m = 5\, tonnes/day$, then it follows from 2.35 that production will continue for 115 and 920 days, respectively, before the temperature of the thermally stimulated zone drops by half. If $m = 10\, tonnes/day$, then the corresponding estimates are 67 and 460 days.

Note that the conductive and convective cooldown times exhibit different dependence on the length scale of the heated region: the former scales with length scale squared; the latter, with length scale cubed (cf. 2.28 and 2.31). Therefore, the cooling of a relatively small heated region is dominated by convection (for a producing well), whereas conductive heat transfer plays the dominant role in a large heated region.

2.6.3 Cooling of a Thermally Stimulated Pay Zone by Simultaneous Conduction and Convection

The rates of conductive and convective heat transfer are additive quantities. Accordingly, the cooldown time τ due to the combined action of both mechanisms should be estimated by adding the corresponding inverse cooldown times τ_1 and τ_2 as

$$\tau = \tau_1\tau_2/(\tau_1 + \tau_2) \tag{2.37}$$

Substituting the estimates for the cooldown times due to both mechanisms given after formulas 2.28 and 2.36 into 2.37,

for $r_m = 5$ and $m = 5$ tonnes/day, $\tau_{1/2} = 94(115/(94 + 115) \approx 52$ days;

for $r_m = 5$ and $m = 10$ tonnes/day, $\tau_{1/2} = 94(67/(94 + 67) \approx 39$ days;

for $r_m = 10$ and $m = 5$ tonnes/day, $\tau_{1/2} = 380(920/(380 + 920) \approx 270$ days;

for $r_m = 10$ and $m = 10$ tonnes/day, $\tau_{1/2} = 380(460/(380 + 460) \approx 208$ days.

2.7 Analysis and Conclusions

What are the prospects of increasing the flow of the conventional oil after warming up of the depleted wells? In Russia such oilfields retain up to 50% of the original deposits in the productive layer, in the USA the fraction is approximately one third. The treatment outlined above analyzes the stimulation of oil output after warming up the well vicinity using vapor or the mixture of vapor and heated gas (CO_2). This heated mixture (produced by the kerosene or diesel-run generator) can be pumped right from the surface into the oil wells with the depth up to 700-800 meters. In this respect the output rate of useful energy is approximately 50%. This implies that warming up the layer takes half of the heat produced in the generator compression chamber. In order to ensure heat delivery at greater depth it is necessary to use gas and vapor mixture generator dropping it into the oil well. In this case the output can reach 80-90%.

Take as an example an oil well with the primary flow rate prior to warming up amounting to 0.3–0.6 tons per day, situated in a conventional depleted oilfield with a layer up to 10–20 meters, the original temperature 40 ℃ and the porosity 20%.

A non-sophisticated calculation was been made here using the numbers from [3] presupposing the rate of pore oil-infillement amounting to 40%. The results indicated that in this hypothetical case after warming up the layer to 140 ℃ the oil viscosity is reduced 15–25–fold.

The equality

$$Q = 2\pi L r_1 d(P_2 - P_1)/[\mu_1(r_2 - r_1)] \tag{2.14}$$

where

$$P_2 - P_1 = 20atm \tag{2.38}$$

refers to the conditions of very depleted well.

Since at the same time the layer permeability and pressure stay approximately the same, the oil extraction process will become 15–25 times as fast and the period of time the oilfield needs maintaining is thus 15–25 times shorter .

During long periods of oil extraction from depleted oilfields the oil flow in the well is hampered by the more viscous hydrocarbons accumulating at the entrance of the well. In the process of warming this mass up to 100-120 ℃ and obliterating the braking zone, maintaining the oil well may become commercially viable simply through periodic heating in this fashion. A simplified calculation, taken in part from [2, 3] is below.

The layer thermal capacity (sandstone) is recognized equal to 0.2 large calorie per kg/degree, oil thermal capacity 0.52 $Kcalkg^{-1}$/℃ [3]. The rock thermal capacity (92%) with oil (8%) amounts in this case to 0.24 $Kcalkg^{-1}$/℃. The diesel calorific value is 10000 $Kcalkg^{-1}$/℃. The sandstone density equals to 2.6 kg/liter. It is presupposed that a layer part having a cylindrical form with the diameter and the height of 20 meters, the volume of 6248 m^3 and the mass of 16245 tons situated in the vicinity of the well was heated. The whole process consumes 64 tons of fuel with the output of 50% and 40 tons with the one of 80%. Under the condition of the heated braking zone and oil viscosity reduced by 15-25 times the flow can be expected to increase from 0.3–0.6 to 5–10 tons per day. According to [3] the temperature reduction from 140 ℃ to 90 ℃ during 208–270 days leads to the flow decreasing by 2–3 times. The second and next heating cycles will consume up to 32 tons of diesel fuel if pumped from the surface (with the output of 50%) and 20 tons if pumped from the generator dropped into the well (with the entailing output of 80%).

In the process of every cooling cycle from 140 to 90 ℃ the quantity of the additional oil can be expected to amount to 900–1350 tons. In this respect the diesel fuel expenses during the first (40–64 tons) and the entailing heating (20-32 tons) are quite acceptable. The price correlation between the diesel fuel and crude oil is approximately 2.5, which means that the fuel expenses for the layer heating lie within 6–15% of the additional oil cost.

In summary, the following observations need emphasizing: in the process of warming of the productive layer rock in the oil well vicinity the oil extraction in the depleted oilfields is highly likely to become profitable, even more so than the commercially lucrative bitumen extraction with the burning of 20% of the extracted hydrocarbons.

Calculations were verified against the results of thermochemical treatments of oil-bearing rock samples in laboratory tests. In field tests, binary mixtures of aqueous solutions supplied into the borehole through two separate ducts were used. The solutions mixed and reacted exothermally as they entered the surrounding region. Four wells were treated by this method in Perm oil fields. The highest increase in the permeability of a thermally stimulated pay (by a factor of 50) was attained for heavy oil (0.96 g/cm^3) by treating well no. 9043 of the Shumovskoe field in 2004. (Permeability was estimated from the water imbibition rate at driving pressures of 120-140 atm measured with a pump pressure gauge.) In summary, both laboratory and field tests have shown that a temperature rise of 100 degrees can lead to an increase in productivity by about one to two orders of magnitude due to reduction of oil viscosity (see Table 2.1).

The most promising thermal stimulation techniques may provide a basis for drastic improvement in production schemes not only for highly viscous oil, but also for conventional oils. The results of work on wells treated with chemically reacting mixtures [4], supported by laboratory test results, demonstrate that thermal stimulation of conventional oil reservoirs can be made cost-effective if a reservoir region of radius 15–20 m around the well is heated one to two times per year.

The cost of a treatment by large-scale thermal stimulation can be estimated by noting that the oil-bearing rock mass to be heated around the well must be at least 15,000–20,000 tonnes. In the case of successful periodic thermal stimulation, the production period can continue for 2 to 3 years for an average reservoir.

Oil field region (Perm)	Well type (no.)	Quantity measured (units)	Rate before treatment (date)	Rate after treatment (date)
Kurbatovskoe	production (169)	daily production (tonnes)	0.7 (Jun-04)	4.2–5.0 (late Oct-04)
Logovskoe	production (140)	daily production (tonnes)	0.6 (Jun-04)	4.4 (Nov-04)
Un'vinskoe	water–flooding (250)	daily water influx (m^3)	14.8 (Aug-04)	67 (Nov-04)
		from 8–12 m^3 (Nov-03) to 172 m^3 (Dec-04) and to 88 m^3 (Apr-04)		

Table 2.1: Results of field tests of prototype TGDF technology in Perm oilfields (Certificate of Test Results, Ural–Dizain, Perm, 3 Nov 2004).

(Recall thermal stimulation of bitumen-laden sands in Canada, which resulted in cost-effective production rates.)

A thermally stimulated reservoir will produce more oil, as compared to an unheated one, for at least three reasons:

A. The viscosity of the extracted oil is drastically reduced.

B. Asphaltene, paraffin, and other deposits impeding the influx of oil are much less likely to form around the drawdown cone.

C. Gas release from the oil contained in a large heated rock mass gives rise to a higher reservoir pressure, increasing the production rate.

Finally, it is to be noted that the present analysis of optimal temperature distribution can also be helpful when the energy E is injected into the formation through only one well. In this case, a near-optimum temperature distribution analogous to 2.19 can be created by controlling the rate of heat injection.

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M. Goodwin** and
N. M. Kuznetsov***

CHAPTER 3

Experimental Results & Discussion I: Initial Binary Chemical Approach

3.1 Introduction

The initial approach taken on this project was to use a chemical generator to create the TDGF process. This would be used in tandem with hydraulic and vibration processes to maximise oil recovery from depleted wells.

The Chemical Generator, as distinct from propellant-based gas generators was envisaged to operate in continuous mode, in the same manner as a torpedo or rocket engine. The generator will be employed to stimulate the use of a pay zone in a well as a reaction chamber fed through a chemicals supply system. With such a generator, further improvement of stimulation efficiency could be achieved by combining the advantages of hydraulic and thermo chemical fracturing schemes (high power, continuous mode of operation, and high efficiency) in a single engine-like device fed with fuel and oxidizer through separate supply lines. Unlike automotive, aircraft, or marine engines, the device must produce a jet of burned gas at an ambient pressure of up to hundreds of atmospheres. As a result, the useful power output can be increased by up to ten times as compared to existing stimulation devices.

A borehole-mounted gas jet generator was designed on analogies to the torpedo engine that can produce the required effect at a depth of up to 2.5 km (see Fig. 3.1). The borehole-mounted gas jet generator was expected to be particularly useful as a source of the high-temperature gas required to stimulate production of conventional, heavy and even bitumen-rich oils, which are key resources abundant in North America.

The generator was intended to be multipurpose. While working on low power in a pulse mode, by pressurizing and depressurizing a small bubble of the gas which is situated in a liquid opposite the seam, it may be used for diagnostics of injectivity (porosity) of separate layers and seams. At medium power, it would appear to be suitable for cracking research of the viscous oil in a well, for example, for the reducing the proportion of sand carried out from layers with bitumen heated oil on fields where such a problem exists.

3.2 TGDF summary

The core TDGF technology involves the following key processes:

- The first portion of the high-temperature foam penetrates the pay, driven by a pressure head much lower than required to inject an inert fluid at ambient temperature.

- The pay is fractured and heated by the large amount of gas produced in a continuing intense reaction.

- The inflow of oil into the borehole from the cracks treated with a chemically active gas increases as the oil viscosity decreases and permeability increases.

- The increase in permeability must be combined with quick extraction of oil before the heated pay cools down. Therefore, special post-treatment and operational standards must be developed and strictly followed.

TDGF technology is optimally implemented in a multistage treatment procedure:

1. At the vibration–treatment (VT) stage, 100 to 200 kg of heated gas are injected into the pay by means of vibrational combustion, with a frequency of 5–19 kHz and an amplitude of 1–5 bar, to create initial cracks and facilitate subsequent gas injection;

2. At the pulse–treatment (PT) stage, up to a ton of hot gas is injected into the pay to expand the vibration-induced cracks;

3. At the cyclic–treatment (CT) stage, up to several tens of tons of high-temperature foaming reacting agents may be injected into the pay at a high pressure. A very large increase in the permeability of a layer was noticed when it was heated on a field with heavy oil.

Working at deposits with normal levels of oil, heating up a layer and removing the heated oil around the well before it cooled made it possible to increase the permeability of the productive layer and oil–production many times over in comparison with the initial permeability of the layer and initial productivity of the well. All tests before the start of this project were on wells on very depleted fields where the layer pressure was not more than 50–60% of the initial pressure and the average speed of extraction was 1–3 tons a day.

Usually on such fields the period of extraction of additional oil after a stimulation of a well lasts not more than a year and the cost of the next annual additive, as a rule appears to be much less than $100,000. The average treatment costs estimated for four wells in depleted reservoirs were found to be a factor of 1.5 lower than the cost of the additional oil produced during the year that followed after treatment (see Table 2.1, Chapter 2)).

Heating up wells with a small debit for processing by using cheap chemicals is more profitable than steaming: an internal combustion engine working at the bottom of the well will have considerably higher efficiency than tools producing steam from the surface. This also opens the possibility for the removal of heavy oil from deeper wells where the effectiveness of steam procedures is greatly diminished.

3.3 Chemical generator design and prototype

The requirements for the chemical generator were as follows:

1. Reactor
2. Device to mix reagents.
3. Reservoir to receive products of the reaction.
4. Device to measure the amount and speed of receiving solutions through the first channel.
5. Device to measure the amount and speed of receiving solutions through the second channel.
6. Dispenser (regulator) of the pressure in the supply reagents channels.

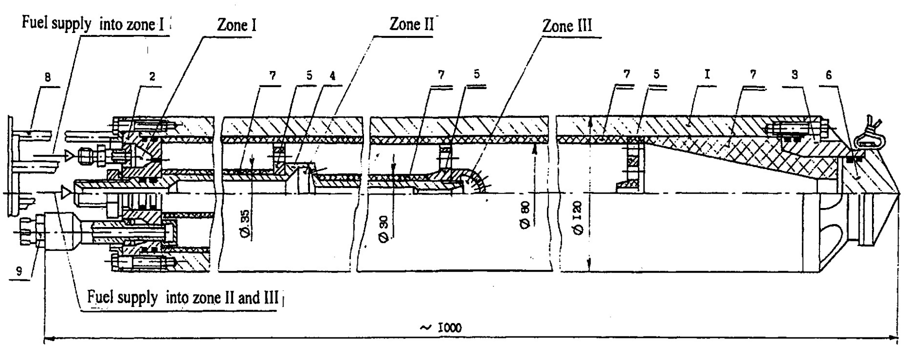

Figure 3.1: Schematic diagram of the proposed chemical generator design. Note: Design of generator prototype presented Patent No 36855 from 27.03.04 (priority from 05.11.03),), Facility for treatment of pay zone,authors: E.N. Aleksandrov, V.V. Dozhdev, E.M. Timohin, patent owners E.N. Aleksandrov, V.V. Dozhdev, E.M. Timohin.

Technical ratings and parameters:
1. Fuel: liquid
2. Fuel supply: pumping
3. Total fuel consumption rate: 0.8–1.0 kg/s
4. Working pressure: 6–30 MPa
5. Operation time: up to 2 hours

No.	Item	Qty	Comments
1	Casing		
2	Injection unit	1	Zone I
3	Nozzle unit	1	
4	Tubular rod	1	Zone II and III
5	Bluff-body flameholder-thrown-off	3	
6	Blank flange	1	
7	Thermal insulation	4	
8	Joint	1	
9	Ignition unit	1	

Figure 3.2: Main units and parts

A prototype machine with manually controlled chemical supply valves was constructed and new FOM chemicals were developed for it (Figs 3.1, 3.2). This generator was used as a prototype rig as a 1000:1 scale prototype of the well generator by volumetric flow rate. It was used to test the delivery of binary chemical mixtures through separate flow channels. The chemical supply system seal was checked using the testing rig at a temperature of 100 ℃ and under changing pressure up to 500 atmospheres at the entrance gate, under the control of the chemists D. Lemenovski and G. Melik-Gaikazov and the technologists V. Dojdev and A. Polovnev.

The first test of such machine with manually controlled chemicals supply system applied to the injection of binary chemical mixes into a working well was done in December, 2003 on a field with heavy oil in the Perm area, Shumovskoe oil field.The reaction zone was heated to not higher than 200 ℃ to preserve the concrete stone fixing external pipe that was required by local technologists. Diluted binary chemical mixes were used. Speed of reception by the layer of liquids, pumped into the well, in process of increasing of speed of reaction and heating up at constant pressure of the liquid at the exit from the pump, increased from 0.078 L/s up to 4 L/s. Therefore the permeability speed of the heated solution into the heated layer during the heating process increased fifty times. After pumping about 2 tons of binary mixes and after the the chemical reaction inside the well was depleted, the production schedule was halted because of an unforeseen side effect: The heated part of the layer cooled before the thickest oil that gathered around the well was taken out, as was intially desired. The permeability of the cooled layer returned to the initial level.

This technology was subsequently applied to stimulate three wells in depleted conventional-oil reservoirs, which resulted in higher production rate that lasted for 6 to 12 months (see Table 2.1, Chapter 2)). The big difference in permeability of a layer between the heated and cooled states was promising.

This thermal approach using cheap binary chemical mixes appears to be of use in processing not only depleted reservoirs, but also for newly operational reservoirs. The TDGF approach has universal applicability because it combines a passive method of increasing extraction (heating) with an active physical method of stimulation such as hydraulic fracturing. Furthermore, we anticipate that its effectiveness can be considerably increased from current levels.

3.4 Optimizing FOM

Relying on the experience of our commercial partners in developing rocket and torpedo propellants, a new FOM composition well suited for utilization in oil wells was proposed. The proposed FOM does not explode at any percentage of dilution with water. The process can be reliably initiated at FOM water concentrations ranging from 0 to 50%. In other words, the interval of admissible water concentration has been increased fivefold. However, there were difficulties to be resolved connected with additional dilution of chemicals, pumped into a well with a fluid (including additional water), leaking from around well layers.

New primers, which produce hydrogen when reacting with water, were also developed. These primers initiate the treatment process by means of a fast exothermic reaction developing upon their contact with the FOM. The reaction starts immediately after the primer-containing ampoules immersed in the FOM are broken and proceeds until the primer is consumed completely. The water content is not an important factor in this scheme, because the primer reacts with both water and FOM. As a result, the reliability of treatment has been significantly improved.

3.5 Preparation of recommended fuel-oxidizer mixture compositions based on theoretical and numerical analysis

To create the diagnostic system and to be able to make prognostic results of processing of the productive layer at depths up to 5 km, a test rig was calculated, developed, designed and manufactured. The scheme of a new generator of gases that are created during the reaction of binary mixtures is shown in Figure 3.3. Such generator is able to work under the pressure up to 500 atm. The generator

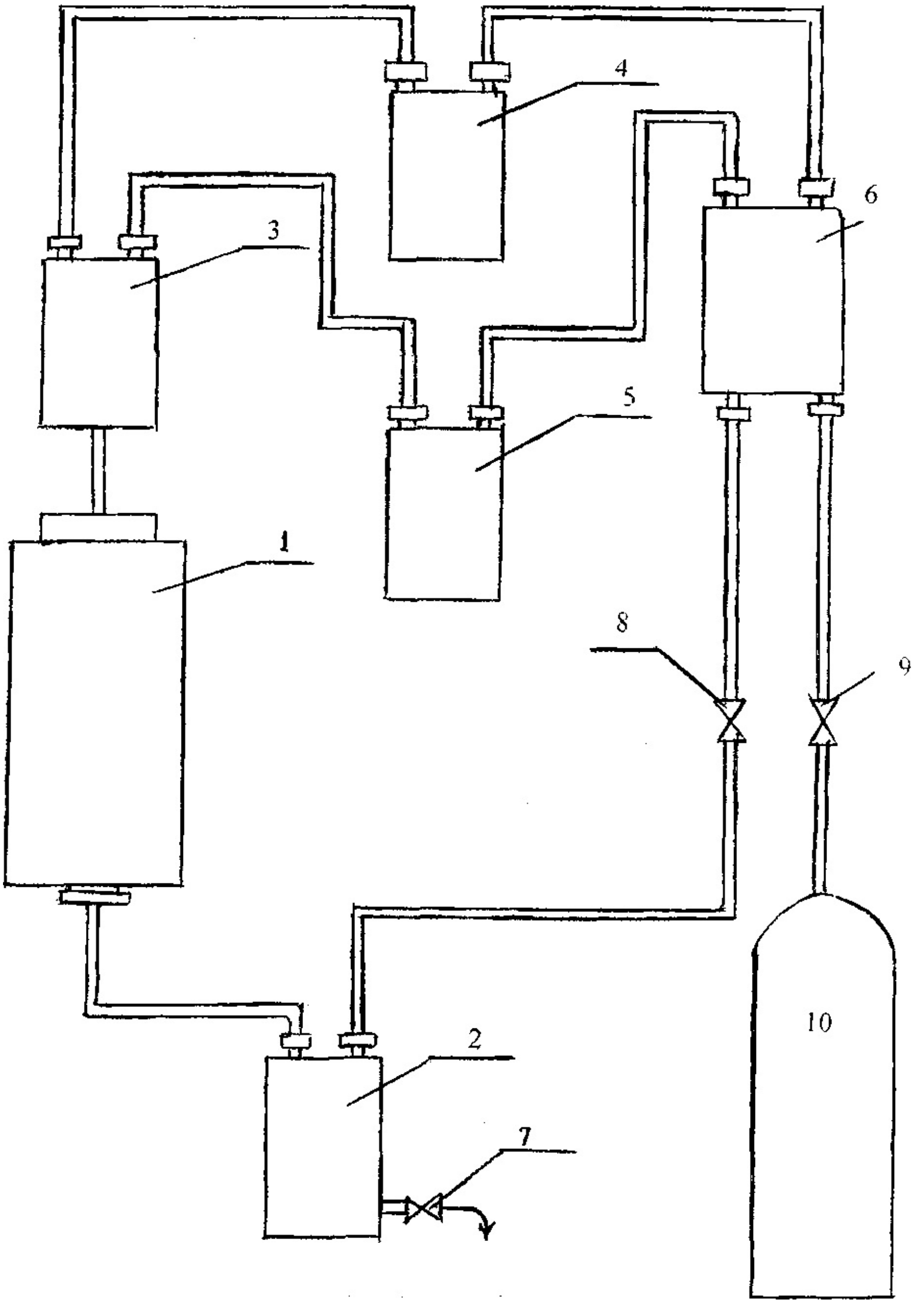

Figure 3.3: Schematic of the revised generator. The picture shows schematically: (1) Reactor, (2) Space to receive the reaction products, (3) Device to mix the reagents, (4) Device to measure the amount and speed of supplied solutions through the first channel, (5) Device to measure the amount and speed of supplied solutions through the second channel, (6) Distributor of the pressure inside the channels of reagents supply, (7 -9) Faucets, (10) Container with compressed gas (nitrogen)

was installed in an armor chamber of the Institute of biochemical physics of Russian academy of science. The picture shows schematically: (1) Reactor, (2) Space to receive the reaction products, (3) Device to mix the reagents, (4) Device to measure the amount and speed of supplied solutions through the first channel, (5) Device to measure the amount and speed of supplied solutions through the second channel, (6) Distributor of the pressure inside the channels of reagents supply, (7-9) Faucets, (10) Container with compressed gas (nitrogen).

Evaluation tests with binary mixtures were made under the pressure of 450 atm in the working chamber and they showed that at such high pressures the gas bubbles in pores and cracks, at slow gas fluids, directed into the depth of the rock, partly slow down the movements of the FOM reaction because the gas present in the pores prevents the binary solutions from contacting and initiating the reaction.

It is possible create a FOM capable of a variable-level combustion. During demonstrations in Saratov region in August 2001, a 120 meters deep column of solution of such FOM, placed at a depth of 4 km, was ignited from below and burned down during 105 seconds. As this has not been reliably achieved for patented chemical mixtures, this research was hoped to bring an improvement in this particular application of FOM.

3.5.1 Measurement of reaction rates and analysis of regimes of reaction in high-pressure chemical reactor and test facility

As it was necessary to check the effectiveness of new chemical additions that would raise the effectiveness of binary mixtures in the test rig, several experiments with the binary mixtures were conducted in the laboratory of E. Aleksandrov:

1. Mono-ethanolamine-nitrate + solution of sodium borohydride.
2. ammonium nitrate + solution of sodium borohydride.
3. ammonium nitrate + solution of sodium nitrite.

4. Mono-ethanolamine-nitrate + solution of sodium nitrite.

Other experiments utilised equipment from laboratories of E. Aleksandrov and D. Lemenovski.

Equipment:

- A resonance fluorescence spectrometer with high near and vacuum UV sensitivity (Russian made, $20,000).
- A high-pressure chamber for testing rock and oil samples fed through a chemical supply system and equipped with high-speed pressure and temperature measurement systems (Made in the USSR, approx. $420,000).
- A Hitachi IR spectrophotometer ($82,000).

3.5.2 Parameters measured

The parameters measured during these experiments were: Temperature (T), heat (ΔT), initial permeability of the sample and its permeability after its treatment with chemicals.

The relative permeability of the sample is equal to ratio of permeability of the sample after processing (Π_E) to permeability of the sample before the processing (Π_0):

$$\Pi_E/\Pi_0 = t_0/t_e. \tag{3.1}$$

3.5.3 Description of the chamber and conditions of the experiments.

The pressure chamber used in these experiments is shown in Figure 3.4.

1. Each sample was formed as a cylinder with sides 60 × 60× 100 mm. A hole with diameter 10 mm and 75 mm deep was drilled in the center from the side 60 × 60 of the sample.

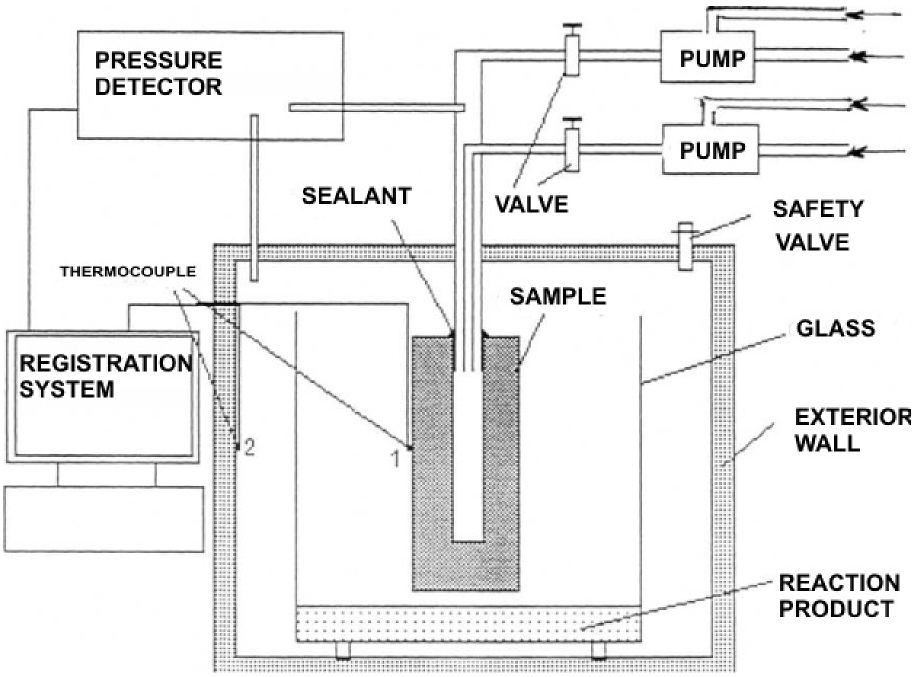

Figure 3.4: Schematic of the testing chamber.

2. The device to supply reagents consisted from two coaxial tubes of different diameters made from stainless steel. A tube with the diameter 10 mm (wall 1 mm), having inside tube diameter 5 mm, was inserted into the 10 mm hole that was made in the sample into the depth of 25 mm and then was sealed with a heat-resistant silicone sealant, thus creating two separate channels to supply reagents to the sample.

3. The outside tube supplied water (0.5 L) and a water solution of the activator of the reaction that created nitric acid (0.5 L). Then the FOM and the liquid initiator of the reaction were supplied simultaneously into the sample that was impregnated with the activator. A fast thermocouple was inserted from the outside side of the sample to measure its temperature. The work was done under chemical "traction" pumping out gas products of the reaction. The size of the sample vessel was increased from 1.2 up to 3 L.

4. The FOM used was mono-ethanolamine-nitrate; the activator was either an aqueous solution of sodium borohydride or of sodium nitrite.

5. The heating and permeability of the sample was measured before and after its processing, in the presence and absence of the nitric acid activator. This permitted comparison of the influence of different kinds of treatment on the permeability of the sample.
   - Water + oil + FOM and liquid initiator.
   - Water + oil + activator + FOM and liquid initiator.

3.5.4 Experimental procedure

The experiments took took place at a temperature of 100 ℃ and a maximum pressure of 2.5 atm. As the reaction chamber approached 90 ℃ the speed of pumping was varied to hold the pressure below 2.5 atm. The pumping rate was varied to keep the reaction chamber below 100 ℃.

When the pumping speed for the reagents was increased, with changing pressure on the sample more than 4-5 atm, the sample lost its strength and began to fall apart during its heating up to 120 ℃. To avoid this, the reagents were slowly pumped at a constant change of the pressure 2.5 atm and heating not more than 100 ℃.

3.5.5 Modelling well parameters

This pressure chamber was used to model of the well conditions at the depth of 2 km (pressure 200-205 atm., initial temperature 35 ℃).

The relative permeability of the sample is equal to the ratio of permeability of the sample after the processing to its permeability before the processing $\Pi_E/\Pi_0 = t_0/t_E$., where t_0 is time of bleeding from calibrated amount through a sample of rare gas (argon) from overpressure 1 atm. till overpressure 0.2 atm. ; t_E is time of bleeding from calibrated one through a processed sample of rare gas (argon) from overpressure 1 atm. till overpressure 0.2 atm.

A pressure chamber was used to study this reactions at high pressure, was filled with argon up to the pressure of 100 atm. Sample processing occured as described above. Bleeding of the products of the reaction from chamber after the safety valve was closed happened at a pressure of 205 atm. It means that the reaction was going at almost constant pressure, equal to hydrostatic one at the entrance to the well of 2 km deep and filled with water.

This experiment implies that the permeability of the sample is almost invariant going from atmospheric pressure to that of a well at 2 km depth.

3.6 Experimental analysis

Experiments were conducted to check the effectiveness of the FOM reaction at different pressures. The experimental procedures were as follows: a sample of oil-bearing rock was exposed to sulphuric or nitric acids, with appropriate additives. The maximum temperature (T_{max}) for the subsequent reaction was measured, and used to evaluate the degree of chemical transformation which had occurred. These experiments were used to determine the optimal combination of acid and oxidizer, and the optimal length of contact time between the FOM and the oil to maximise the temperature increase.

The rock samples were shaped as cylinders with diameter of 5.5 cm and height of 6 cm. In the center of the cylinder drilled a "cup" with diameter of 25 mm and 5cm deep was drilled in which the acid/FOM mixture was introduced. The acid went into the sample through a press-fit tube with external diameter of 24.5 mm and with walls 1 mm thick, made from non-corrosive steel. The reactor capacity was 1 L and the size of each sandstone rock sample was 120 cm^3, with a mass of 310 g. A mass of oil equivalent to 22 g was pumped into the reaction chamber and the temperature increase measured with a thermocouple. After leaving the sample, the chemical mixture entered a draft tube of inside diameter 2 cm and length 120 cm. The remainder of the liquid then entered a waste tank. Experiments were conducted at room temperature (22 ℃). The results are presented in

Pressure (atm.)	sulphuric acid transformation (%)	sulphuric acid T_{max}(°C)	nitric acid transformation (%)	nitric acid T_{max}(°C)
1	22	35	57	78
10	20	43	68	88
50	20	36.5	65	95.5
80	20	47	77[a]	87[a]
800	20	37	71[a]	91[a]

Table 3.1: Results of reaction of acid/FOM mixtures with rock-oil samples at varying pressures. The degree of transformation of the oil mixture (%) and the maximum temperature reached by the reaction (T_{max}, °C) are given. The mass of acid mixture added to the sample in each case was 40 g. The contact time between the FOM fix and the oil was 10 minutes, except for [a], where the reaction time was 5 minutes.

Table 3.1.

The larger T_{max} for the nitric acid samples corresponded to a high degree of transformation of those oil samples, implying an effective reaction, especially at shorter contact times. Carbon dioxide gas and water were liberated as waste products, with hydrogen gas (4.5%) and carbon monoxide (6%) as minor by-products.

The smaller degree of transformation of the sulphuric acid samples is thought to be due to the build up of an acidic sludge, which acted as a cork and prevented dispersion of the FOM mixture through the rock sample.

These experiments were repeated using a sand trap within the "cup" to slow the dispersion speed of the chemical mixture. The results of these experiments are shown in Table 3.2, marked with [a], as against the unimpeded samples.

The results in Table 3.2 demonstrate the reactivity of the nitric acid mixture increases markedly when the sand trap is used to slow down the rate of dispersion. However, such an effect is not seen using the sulphuric acid mixture.

Acid	Pressure (atm.)	transformation (%)	T_{max} (°C)
sulphuric	1	20.5	42.5
sulphuric[a]	1	23	45.5
sulphuric	80	17.0	34.7
nitric	1	53.5	57
nitric[a]	1	67.5	77.5
nitric	80	79.7	93.3

Table 3.2: Further optimisation of acid/FOM mixtures delivery with rock-oil samples. The amount of acid sample introduced into the reaction chamber was 50 g in each case. The contact time between reagents and oil sample was 10 minutes. Samples marked with [a] were impeded with a sand plug to slow down their dispersion into the rock-oil sample.

The implication of this finding is that the nitric acid mixture will have substantially greater effect on the TDGF procedure when its application is preceded by applying pressure to the oil layer, in order to increase the network of cracks in the layer for the acid mixture to disperse into.

3.7 Conclusions

The initial results of design of both the chemical generator and the optimising FOM chemicals were promising. However, at this stage in the project the economic advantages of using another generator method became overwhelmingly apparent. For this reason, the main focus of the project moved from using a chemical generator approach to TGDF technology to a diesel-fuelled, gas-vapor generator solution to TGDF. This is covered in the next chapter.

CHAPTER 4

Experimental Results & Discussion II: Generator Approach

4.1 Introduction

After commencing work on the binary chemical solution outlined in the previous chapter, consultation with our Russian colleagues, particularly Professor Aleksandrov led to the alterion of the final stage of the project from a chemical solution to a diesel-fueled generator solution. This is a particularly attractive move from a cost perspective.

The Russian team had previous experience with building rocket engines and similar gas generators. The revised design for this generator focused upon the ability for a machine to operate on diesel fuel to a depth of 2 km, producing approximately 2 tons of hot gas per hour. There were expected to be numerous technical hurdles to this approach, not least being the construction of a dual cooling system for the generator. This would be expected to both maintain the generator operating temperature within acceptable levels, and also provide gas and steam to the well. Notwithstanding these issues, it was anticipated that a gas generator would be markedly cheaper than a binary chemical approach to providing the third stage of the TGDF technology.

The rationale behind this change, notwithstanding the alteration of the project goals mid–project, is that the cheaper the process, the greater number of existing depleted wells will be candidates for the technology. Increasing this number will have a very positive impact on domestic production as wells can be made to produce longer and at a higher level than before.

The three stage technology was created in Russia, which was intended to be improved and applied in the USA. The technology included the following:

- In the first stage, at the productive layer, up to 100 kg of powder checkers was burnt in the vibro-wave mode that led to formation of a network of not deep cracks around the well.
- In the second stage, at the productive layer, 1 ton of the mixture was burnt, giving in an impulse pressure of 600-700 atm., therefore short cracks were extended up to 10-20 meters.
- The third stage included pumping of binary mixtures in a big amount into the layer, that is character for HFL, therefore cracks were extended and enlarged.

The cost of the processing of a well in the US was assumed to be not more than $50,000 because of more expensive chemicals in the US. Therefore, the possibility to replace more expensive chemicals by a cheaper fuel was investigated. A test processing was made using the experiment rig, by heating the rock with hot gases resulting from a jet rocket engine. Such methods can be used to heat the layer, but the temperature of the gases that go out of the nozzle (1000 ℃) is too high and risks oil pipes being blocked by coke build–up. Therefore methods of reducing the gas temperature were investigated, principally by the introduction of water into the hot gas stream at the exit from the nozzle. This temperature at the exit from the nozzle went down to 300 °C and coke no longer appeared. This indicated the a diesel–fuel powered generator was a viable alternative for the TGDF technology to the binary chemical method.

Rig experiments and theoretical calculations showed by using the diesel–fueled generator, heating the layer with cheap heat, allows an increase in the permeability of the productive layer around the well 10–15 fold, with a resulting decrease in the time taken to extract oil. This will minimize a lot of exploitation expenses of the production. From an economic point of view such technology is highly desirable.

While oil reserves may be acceptable in a world-wide economic downturn, it is clear that it is important the U.S. has the means to make the best use of the oil reserves that it possesses. Using a thermal method on the layer with steam-gas produced at the bottom level of the well can be very effective and productive. Until now, the development of a thermo-steam-gas-dynamic orientation has been limited because of the absence of well equipment that can work at a depth of 1500 meters and still provide protection of the well from overheating. Past efforts to construct a system to heat a well have failed. For example, the system involving Patent# 4078613 has a weakness in the technical solution because the method failed to take into account the change of depth of system and of the backpressure value, for example during the supplying of air. Another system has a combusting chamber, channels for the entry of the air, fuel and water, a direct fuel injection nozzle and a spark unit. The channels for the water supply are located tangentially to the upper part of the combusting chamber and there are several sectors of water discharge at its inside wall. As a weakness of this technical decision it is evident that such scheme of water supply does not exclude the increment of water into the combustion zone through the wall layer with inverse currents and, as the result, the system cannot start if the water supply passes ahead and water gets into the spark unit, or if the water gets into the combusting zone. This will decrease the degree to which the fuel is combusted.

An alternative design involves injecting a heated liquid fuel from a reservoir. The fuel injecting point into the channel is located before a tangentially located branch tube. This system of carburetion has problems because at rotational movements a centrifugal force exists that causes discontinuity of the flow i.e. heavier particles are throwing away into periphery and they do not get high plenitude of combustion of the fuel. There is another system for thermal influence at the layer where a sprayer to inject water is executed as a circular nozzle created with outside and inside jackets of outlet nozzle. The problem of this technical proposal is that minimum open flow area of the cone part of the outlet nozzle has very high temperature (more than 1500 ℃) because of high speed of combusting products and small surface of heat interchange and as the result there is a problem of cooling it down.

The technical task of this project is to raise dependability of the start at any depth of the well where the steam-gas generator will be immersed and to provide safety and high combustion efficiency of fuel due to diminishing of influencing of row of external and internal factors at the working process.

The problem can be solved using the following method. In the proposed variant of receiving the steam-gas through the well gas-generator at any depth of its immersion, first air is supplied into the combusting chamber with a maximum consumption through the cooling tract of the combusting chamber and the through the open flow area, that is manufactured with bottleneck of the current for the maximum mode of work. Then supply the water and fuel are supplied with maximum intensity of flow, at the same time fuel is injected into the section with the critical parameters of the air flow at a condition that there is a certain amount of water flow. After that the formatted air-fuel mixture is ingnited and mix water with combusting products after combusting front in a low pressure zone that is created by narrowing and enlarging the running section of the combusting chamber.

In this zone the air is supplied coaxially through the cooling tract of the combusting chamber first along the flow of combusting products, then against the flow of combusting products. The fuel is injected along the section axis with the critical parameters of flow of air. After the part where the running section narrows, the water mixes with combusting products on the surface of the inside wall of the combusting chamber. Then water is introduced into the combusting products with help of a falloff ring that is installed after the enlarged part of the running section, at the same time as the running processes are controlled with temperature and pressure detectors.

The body of the device comprises: a combusting chamber, an atomizer flanked to the combusting chamber, a mixing chamber, an automatic ignition supply, channels of water, air and fuel supply, measuring apparatuses. Constitutionally, the combusting chamber is manufactured with three coaxial situated cylinders. The cavity between outside and middle cylinders is intercommunicating with the air supply. The cavity between the middle and inside cylinders is intercommunicating with a cavity of the combusting chamber through an atomizer. The atomizer is manufactured with a channel for the air flow like a diffuser with a cylindrical nozzle for fuel supply, situated coaxially at the entrance part. At the same time the channel of the fuel supply has a starting- cutoff valve with a sensitive element. Cavities of the element are connected before and after throttling element situated on the water supply channel. And the mixing chamber is manufactured as consecutive located narrowing and enlarging channels, connected between themselves forming a circular slot connected with the water supply and it has a falloff ring, situated after an enlarging channel. At the same time, a part of the body is manufactured as a cylindrical shell with releasable connections along the generating line. Channels of supply of air, fuel and water, aggregate of automatics, combusting chamber, mixing chamber, information block and an automatic ignition supply are placed on it. The split part of the body is connected with the block of filters from one side and with the discharge jet from another side.

In essence, the design attempts to achieve what has not been achieved before. A generator that can provide heat effectively into a well at any depth up to 1500 meters. There are still many engineers who are aware of the attempts to do such things with the tests that were primarily done in the 1970s. And although a well

M_a	M_{df}	M_w	T_{cp}	T
	kg/s			K
0.35^a	0.024	$0.14–0.27^b$	2360	423–673

Table 4.1: Parameters for basic operating mode. M_a is mass flow of the air (kg/s). M_{df} is the mass flow of the diesel fuel (kg/s). M_w is the mass flow of the water (kg/s). T_{cp} is the temperature of the combusting products (K) and T is the outgoing temperature at the exit from the nozzle (K). [a] using compressor CD-18/251. [b] Minimum and maximum values.

test has not yet been conducted,it is thought to be highly likely that this design will resolve the problems mentioned earlier and allow the productive transfer of heat into the zone with the resultant increased oil production.

4.2 Gas-vapor generator (GVG): technical specifications

. The work on this equipment was contracted to three separate companies. Prometey was to build the generator and ChemAuto to construct the chemical supply and cooling system. Geotechnica was to develop the operating and control equipment for the generator.

The proposed well generator was intended to work in combination with a mobile complex providing pressure up to 250 atm at the exit and providing 0.35 kg of air per second. A calculation of parameters for the basic operation mode was made, taking into account parameters of the compressor CD-18/251, expenditure of the fuel at the excess air factor $a = 1.0$ and the temperature of the steam-gas 150 ℃and 400 ℃. Results of the calculations are in Table 4.1.

In this proposed scheme it is necessary to use a nozzle with a critical section installed at the exit of the compressor, i.e. at the wellhead. Accuracy of maintenance of pressure by the compressor ± 5 kg/cm^2 at nominal value of $250 kg/cm^2$ should provide change of the expenditure of air only ± 2%. The installation of such a nozzle after the compressor is because it is necessary to exclude the influence (pipe PCP) on the start and the compressor could work at the basic mode. If there is a regulator of the fuel expenditure, the change of difference in the fuel highway from adjusting value in a range from 5 up to 50 kg/cm2 will change the amount of fuel only for 10 - 15%. Going from the above-stated under the offered scheme it is possible to provide factor of surplus of air in a limit $a = 1.05 - -1.25$.

To start the machine automatically at big depths, it is necessary to raise the pressure at the moment of water supply at the pay zone, prior to commencing operation of the rig. (Calculations showed that, for example, at the depth of 1500 m it is necessary to raise the pressure up to 33.5 kg/cm^2) During the basic operating mode of the generator after the initial starting period, water flow rate will be steadily increasing. As a result, the rate of change of the water pressure on the wellhead needs to be automatically controlled after the start of the machine (to keep the temperature of the gas in a planned range).

It is necessary also to install a packer at 100-200 m above the productive layer so as not to effect the speed of submission of heated gas into the layer. For maintenance of the specified expenditure of fuel at the start, the pressure at the wellhead must also be considered, as well as the density of the fuel, resistance of the fuel path and the depth of generator immersion.

4.2.1 Overall generator specifications

The design of the generator can be seen in Figures 4.1 & 4.2. Full technical specifications of the generator design are below:

At the pay zone level it produces the hot steam-gas with specified parameters of temperature and pressure.

The product works as a part of an energy-plant that contains:

1. Air compressor, CD-18/251 (in Russia) manufactured by “Compressor plant”, Krasnodar.

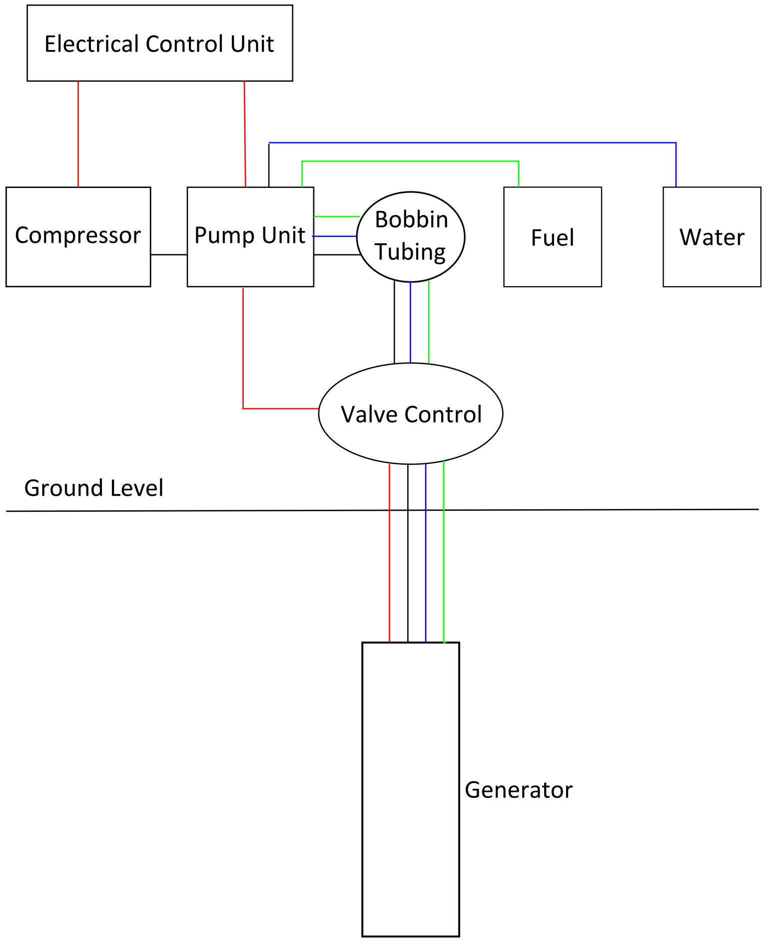

Figure 4.1: Schematic of the Gas-Vapor Generator.

2. Fuel supply system with a pumping station and pipe-line with the diameter of the open flow area not less than 8 mm.

3. Water supply system with a pumping station connected to the tube space through the wellhead of the well.

4. Block of automatic control that guarantees the start, operating regime with maintenance of the specified expenditure of the air from compressor and turn off at the command of the operator if the pressure in the well rises higher than an allowed value.

5. PCP with round-trip equipment.

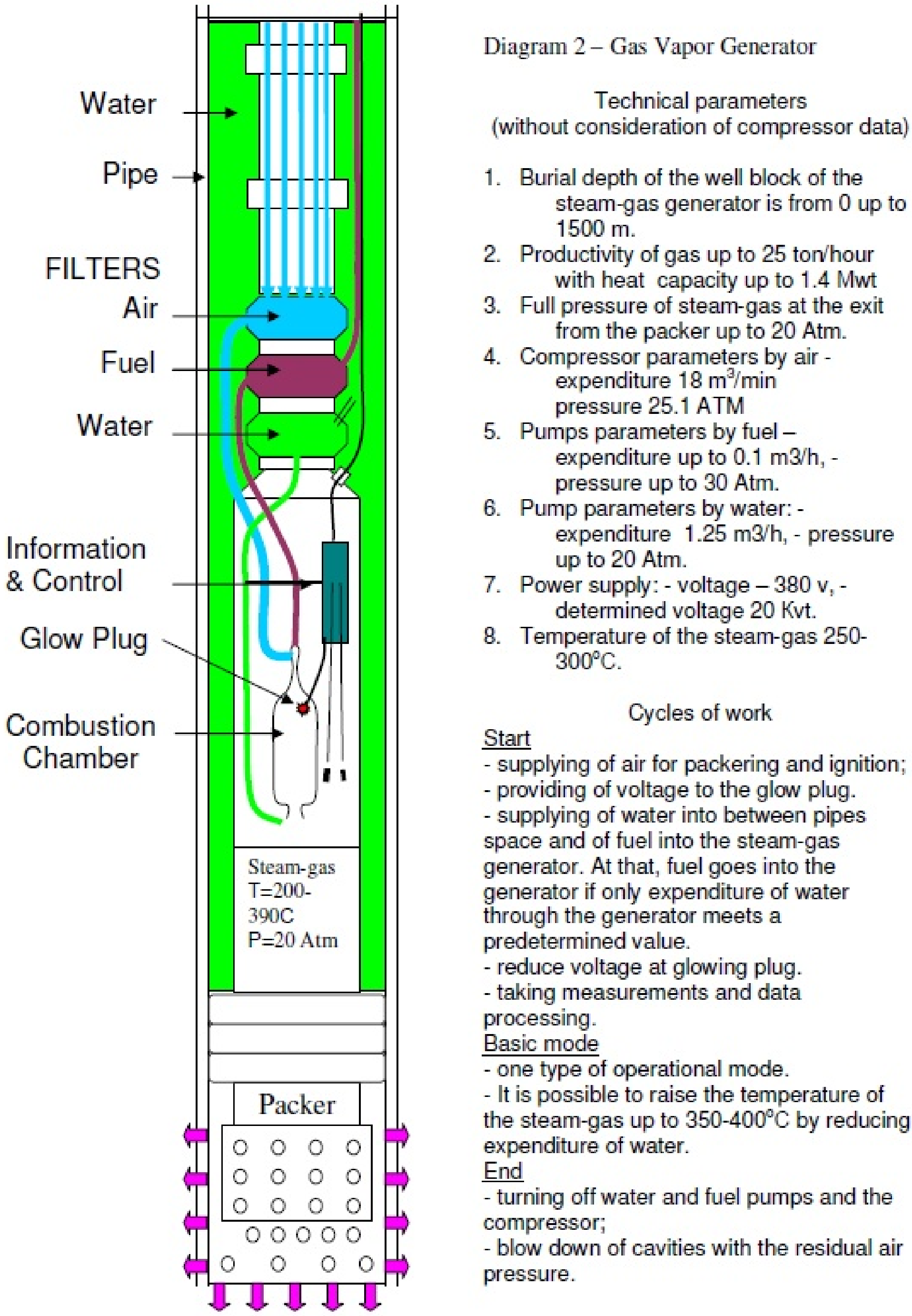

Figure 4.2: Diagram of GVG.

6. High temperature packer with a check valve at the exit.
7. Geophysical armored cable (four cords) with round-trip equipment.

- The product was intended for production of the steam-gas in the well at any depth up to 1500 meters, as well as at the pay zone of the well.
- The product provides a remote start (opens the valves and enables plugs) at one command.
- Stabilizes specified expenditure of the fuel and water at different depth.
- Automatic turn off if the water expenditure gets down from specified amount.
- Register the pressure and temperature of the outgoing steam-gas.
- The product goes into the well placed on the PCP through which the air is supplied.
- The product takes water from the tube space.
- The product contains and unit to connect to the pipe line of furl supply.
- The product has a sealed electrical connector for the cable.
- The product must have a clutch coupling to connect the packer at the exit.

4.2.2 Composition of the well product

- Combusting chamber with an ignite device,
- Block of filters for air, fuel and water,
- Automatic aggregates,
- Informative block.
- All the specified aggregates are situated in a commune protecting pipe.

Outgoing parameters of the product:

- Amount of steam-gas produced: 2.0 Tons/hour.
- Outgoing pressure of the steam-gas, not more than 19.5 atm (195 kg/m^2).

Overall and weight characteristics:

- Maximum diameter of the block along the protecting pipe: 130 mm.
- Length of the assembled device: not more than 10 m.
- Weight of the block: not more than 180 kg.

Specifications of the steam - gas generator.

- Depth of immersing of the well block of the steam - gas generator - from 0 up to 1900 m.
- Productivity of steam-gas up to 2.5 tons/hour with thermal capacity up to 1.4 vt
- Full pressure of the steam-gas at the output from nozzle under the packer - up to 20 mPa.

Parameters of the air compressor:

- Expenditure of 18 m^3/min
- Pressure 25.1 MPa

Parameters of the fuel pump:

- Expenditure up to 0.1 m^3/hour
- Pressure up to 30 MPa.

Parameters of the water pump:

No.	κ_i (mDarcy)	κ_f (mDarcy)	κ_i/κ_f	Gas temperature ℃	Gas used
1	22	12.0	1.83	500	Ar
2	22	4.0	5.50	600	Ar
3	22	0.6	36.70	750	CO_2
4	22	0.2	110.00	1020	CO_2

Table 4.2: Rock sample tests in the absence of water.

- Expenditure 1.25 m^3/hour,
- Pressure up to 20 MPa.

Electro supply:

- Power - 380 V,
- Capacity - 20 kV.
- Temperature of the steam-gas 250-300 ℃.

4.3 Results: Combustion of oil-saturated rock samples

The results of the processing of samples of the rock, saturated with oil, reacting with products of the combusting reaction of the mixture of diesel fuel and air are displayed in Tables 4.2 & 4.3.

The testing rig was used to measure the impact of hot rare gases on a sample of the rock both in the presence and the absence of water at the combusting zone. Table 4.2 shows that the permeability of a sample of the rock decreased after high temperature processing (from 500 up to 1020 ℃) in the absence of water.

By contrast, Table 4.3 shows that the permeability of a rock sample increased after treatment with the mixture of hot gas and water steam at two temperatures.

No.	κ_i (mDarcy)	κ_f (mDarcy)	κ_i/κ_f	Gas temperature ℃	Gas used
1	22	14	1.57	520	50% Ar + 50% steam
2	22	44	0.50	400	50% Ar + 50% steam
3	22	66	0.33	300	50% CO_2 + 50% steam
4	22	110	0.20	210	50% CO_2 + 50% steam

Table 4.3: Rock sample tests in the presence of water.

It can be seen from both Tables 4.2 and 4.3 that the time taken to heat of the rock and the subsequent permeability increase depend largely upon temperature of the treatment, and that this should not be higher than 400 ℃.

4.4 Testing the prototype generator

By late January 2007, the generator was at a factory shop in its assembled condition but a part of its protective outer body was taken off. After a preliminary test, there was a decision to replace an incandescent plug for a more dependable one, because the previous one did not show stable results at maximal pressure (it depended on the depth of the immersion). All other units and blocks of water, fuel and air filters passed tests and worked well. The control system was not able to be tested because the generator was already tested and connected to the stand. The testing of the control system could only occur after assembly of the entire installation on a platform in its autonomous mode. Another problem, that had to be fixed involved some component parts that were received from other companies had connections that did not fit the ones that were already being used. Arrangements were made to manufacture new connection units. Decisions were also required about connections for water fuel and air at the well. Universal connections were fabricated, since each field can be using different equipment. Several pictures of the generator system mounted to the stand and also operating are shown in Figure 4.4.

Figure 4.3: Several pictures of the Gas-Vapor Generator.

There were substantial issues with the control system that had to be resolved. Excessive vibrations were initially experienced in the system during operational tests. Additionally, the control system was too aggressive in making minor changes to the fuel, air, and water mixtures based on very minute changes in temperature and pressure. Unfortunately, the modifications to the generator that were anticipated to solve this problem could not be completed before the

Figure 4.4: Images of the control system guages, control system readout and pump unit for the Gas-Vapor Generator (Geotechnica).

cancellation of the project.

Stand testing continued along with evaluation of continual minor problems that were preventing the planned complete run testing (30 - 50 hours) involving continuous operation.Problems with the spark plugs, condensation in the air lines related to the stand testing system, the size of the transformator and other matters required resolution. The Generator did undergo an effective and powerful stand test where all systems appeared to operate correctly with consistent temperature of 240 ℃ and 200 atm. A problem was encountered at the head of the generator where the metal was actually melted on the inside from the heat flow in the combustion chamber. The issue was recognized from the outset with the expectation that the air supply would help to solve this problem. In retrospect, it would require a more robust solution that will likely require a new design with a cooling jacket surrounding it. This problem requires a reevaluation of the surface shape and metal used at this point to resolve the problem. However, it was considered major milestone to have had it operating for about 2 continuous hours. This test substantiated confidence that the problems previously encountered, although nagging, could be resolved.

The system engineers raised the issue of a housing container to mount the control system and allow an operator to safely operate the system in spite of any inclement weather. The container system would also allow a sensible approach to the routine transport of the above ground components. Although it was always understood that this issue would need to be resolved, it was never fully recognized at the project conception that this control and pumping system would be as big and complex as they have become. This was considered for future iterations of the generator design.

4.5 Conclusions

Having reached a stage in the project where the foundation for the remainder of the research has been laid - in that all supplier contracts had been placed and funded, while encountering significant issues troubleshooting the prototype generator, the combination of the Russia-Georgia conflict and the economic downturn led to the sudden cancellation of the project. While these geopolitical and economic factors were large and unavoidable complications to the project, the groundwork laid by this project and the preliminary results achieved are worthy of further exploration when the economic and political climate permits. TGDF technology, as this report has shown, is an embryonic technique with massive potential benefits to the efficiency and longevity of oil wells in both new and established oil fields. It is to be hoped that the findings of this project provide a starting point for future research into this topic.

CHAPTER 5

Conclusions

In summary, this report has demonstrated the need for new technologies to increase the productive lifespan of oil wells, not least for economic reasons. The merits of Thermochemically Driven Gas-Dynamic Fracturing have been put forward as a possible method whereby oil production is increased within a well by heating of the rock containing the oil deposit, thus decreasing the viscosity of the oil and increasing its flow rate. Initial testing of this concept in Russian oil fields showed promising results.

Two approaches to achieving the increase in rock temperature have been put forward: a chemical approach, whereby a combination of a fuel-oxidizing mixture (FOM) and chemical activator is used to create a exothermic chemical reaction within the well payload, thus heating the rock; and a fuel approach, where a diesel-fuel generator is used to ignite fuel at the bottom of the well-head, thus raising the temperature.

Although this latter approach consumed most of the time and resources of the project, it is to be hoped that the results of the initial chemical testing will bear fruit for future research avenues.

This latter approach was investigated via the designing and construction of a diesel-fuel generator which could operate at the depths obtaining in a well-head, which relevant control apparatus to monitor and sustain the rock heating process as required. Construction of a prototype generator was accomplished, and initial testing was commenced, with positive results for increasing the viscosity of rock-oil samples using this fuel generator, both in the presence and absence of water.

As is to be expected in such a complex project, there were a number of issues relating to the smooth operation of the prototype generator which proved difficult to resolve. In the event of the project cancellation, these were still unresolved, but the generator has proved its ability to operate at temperatures of 240 ℃ and 200 atm. This is a promising result, and merits further exploration by future researchers in this area.

Owing to the difficult geopolitical climate, with the Russian-Georgia conflict occurring during the latter half of this project, as well as the economic downturn, the project was summarily cancelled before prototype testing was complete. While such a decision is comprehensible, such large factors being out of our control, combined with the promising intial test results for the diesel generator, it appears clear to us that this project is worth further exploration. The preliminary results outlined in this report have demonstrated its viability, and the economic need for such technology is clear. It is to be hoped that Thermochemical Gas-Dynamic Fracturing such as has been outlined in this report will be the subject of future research, building on the foundations laid here, and will bear fruit for the oil industry in years to come.

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