Geothermal-Electric plant offshore using the ELI concept

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Summary:

The technical and economical aspects of the ELI concept for the reutilization of existent oil/gas wells and installations in the North Sea is evaluated. The concept exploits geothermal energy by circulating a fluid in a closed loop thermally connected to a power plant on a platform to generate electricity. The main production costs of the electrical power generated is associated to the drilling of the connecting section between the two existing wells. The ELI concept in the North Sea might only be found economically attractive provided that drilling costs can be reduced by, at least, a factor of 10 compared to present cost level.

Key-words: geothermal energy, electric power production, heat transfer

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Preface

The present document is the result of a collaboration between RF-Rogaland Research and SINTEF Thermal Energy and Hydropower to study the technical feasibility and economical viability of a geothermal-electric power plant off-shore in the North Sea using the ELI concept (Norwegian patent pending 950306). This work was funded by the Norwegian Research Council (NFR) under the project No. 32897/212.

The report is divided in three parts. Part I corresponds to the study of heat extraction conducted at RF-Rogaland Research and the economical evaluation of a geothermal plant offshore using the ELI concept. Part II consist of the study of electrical power production conducted at SINTEF Thermal Energy and Hydropower. Part III is dedicated to the conclusions and recommendations based on the results obtained.

We attach a description of the ELI concept in Appendix A and the final version of the report sent to the Norwegian Research Council in Appendix B.

Part I

HEAT EXTRACTION STUDY

Table of Contents

List of symbols

a	radius of the wellbore
c	specific heat at constant pressure of the solid or geological formation
c_f	heat capacity per unit mass or specific heat of the injection fluid
D	diameter of the wellbore
e	rate of change of the internal energy of the primary fluid
h	convection heat transfer coefficient, convection surface conductance
$\mathbf{j}$	heat flux density
j_s	normal component of the heat flux density at the boundary surface
k	thermal conductivity of the rock
k_{pipe}	thermal conductivity of the casing or pipe wall material
k_{cem}	thermal conductivity of the cement around the pipe
k_H	horizontal or parallel to the plane of bedding component of the thermal conductivity tensor
k_V	vertical or normal to the plane of bedding component of the thermal conductivity tensor
L_{diff}	length scale associated to the heat diffusion process
m	mass flow rate in the primary loop
$\mathbf{r}$	position vector
R_i	inner radius of the pipe
R_o	outer radius of the pipe
t	time
T	instantaneous temperature of the formation at a given point in space
T_b	bulk temperature of the primary fluid, also known as mixing cup temperature
$T_{b,in}$	bulk temperature of the fluid at the inlet of the primary loop
$T_{b,out}$	bulk temperature of the fluid at the outlet of the primary loop
U	average velocity of the primary fluid
w	shaft power delivered by the pump in the primary loop

Z Cartesian coordinate equal to minus the true vertical depth

z coordinate along the axial direction of the well/pipe, measured from the inlet point of the primary well, also called *measured depth*

ρ density of the rock formation/solid

ρ_f density of the injection fluid

τ_a time scale associated with the heat diffusion in the formation over a distance a

1 Introduction

From the early days of mining it has been known that the temperature in the Earth increases with depth. In the broadest sense, *geothermal energy* is the energy stored at depth underground. In this report we evaluate the possibility of using geothermal energy for production of electrical energy.

Measurements of temperatures in deep drill-holes show that the rate of increase of temperature with depth, i.e., the so called *geothermal gradient* is between 10°C and 50°C per km on land. Measurements in the ocean floor give about 30°C-40°C per km. The values referred to above, and all that will be said below, correspond to regions far away from volcanic activity where observed temperatures are much higher. The variations in the value of the geothermal gradient are due mainly to differences in the *thermal conductivity* for the different rock types (Carslaw and Jaeger,1959). When these differences are taken into account observations at all points of the earth (including the ocean floor) are consistent with a heat flux density in the range 25-84 mW/m^2 (0.6-2.0 $\mu cal/cm^2$). On the other hand the heat stored in hot dry rock is huge: The heat obtainable from cooling 1 cubic kilometer of rock by 1°C is equivalent to the energy contents of 70000 tons of coal (Smith, 1973). Although drilling has by now reached 12 km, the depths from which heat might be extracted economically are unlikely to be greater than 5 km with present drilling technology. As of this writing geothermal production wells are commonly 2 km deep, but rarely much over 3 km. With an average geothermal gradient, a 3 km well in dry rock formation would have a bottom temperature near 100-120°C. Even limiting the possibilities to the uppermost 3 km of the crust, drilling costs has made it uneconomical to tap this energy in but relatively special regions of the earth. The drilling technology is similar for geothermal fluid as for oil. But as the energy content of a barrel of oil is much greater than an equivalent amount of hot water, the productivity and the economic requirements of the geothermal wells are much higher than for oil wells.

Norway has several platforms in the North Sea. Some of the production fields of oil and gas will be shut down in the near future due to their low production. The cost of removing the platforms is high and alternatives to condemnation are very interesting to lay open. Power production based on geothermal energy is one option for utilization of the existing wells and platforms.

In this work we analyze the possibility of reconverting the abandoned wells in the North Sea into geothermal-electrical power plants. The scope of this evaluation is focused on a specific (binary cycle) type of geothermal plant using the concept of *Electricity production by Injection of a Liquid fluid* to be referred to as the ELI concept throughout. In the ELI concept heat is tapped from a hot formation by circulating an injection fluid in a closed *primary* loop. The thermal energy convected by the injection fluid is transferred to a *secondary* loop through a heat exchanger on the surface. The conversion from thermal into electrical energy takes place in the secondary loop where, a vaporized working fluid is expanded through a turbine, condensed and reheated for another cycle.

In Section 2 we discuss the basic theory needed to describe the heat transfer process. In Section 3 we propose a model for a primary loop of a binary cycle geothermal plant using the ELI concept. By solving the model we obtain an upper bound to the thermal power that can be extracted from the formation. Using typical data for existent installations and physical properties of the geological formation in the North Sea we calculate the maximum thermal power that can be extracted from the formations. In section 4 a cost model is presented. In Section 5 we discuss the results obtained taking into account both Part I and Part II of this document. The bibliographic references are collected at the end of this part.

2 Basic Theory

When different parts of a geological formation are at different temperatures, energy in the form of heat flows from the regions of higher temperature to those at lower temperature. The laws of thermodynamics allow us to predict the final temperatures after the equilibrium is reached. The rate at which this energy transfer occurs and the duration of the process can be only determined by a heat transfer analysis. A complete analysis of the heat transfer process requires the consideration of three different basic mechanisms: conduction, convection and radiation. Radiation heat transfer is negligible at the temperatures found a few kilometers deep. Body convection in hydrothermal resources like the geopressured hot water aquifers believed to exist in the North Sea basin is also neglected. Recent studies (Bjørlykke et al. 1988) have shown that the setup of convection cells in sedimentary basins is very unlikely. This is so because the Rayleigh number governing the free convection mechanism (Tritton, 1978) is below the critical value. In any case the setup of free convection cells in the aquifers underground seems to be very controversial[1]. Heat transfer mediated by conduction is thus the only mechanism we shall consider in the body of the solid formation. In addition, heat convection takes place in the well-formation interface.

Let us concentrate on the primary loop of the geothermal plant using the ELI concept discussed in the introduction. Due to the natural geothermal gradient the temperature T of the formation underground is initially higher than the temperature at zero depth. Fluid at a bulk temperature $T_{b,in}$ is pumped into the inlet of the primary loop (or injection well) at a constant mass flow rate m. Wherever the temperature around a given section of the well-bore is higher than the bulk temperature of the fluid, heat will flow from the formation to the fluid inside the duct. The total thermal energy extracted from the formation per unit time, here referred to as the *geothermal heat power* q of the geothermal installation, is equal to the net heat flux across the well-formation interface:

[1] E. Prestholm (Basin modeling group, RF-Rogaland Research), private communication.

$$q = \iint_S \mathbf{j} \cdot \mathbf{n} \, \mathrm{d}S \quad , \tag{1}$$

where $\mathbf{j}$ is the *heat flux density vector* (energy crossing a unit area of surface per unit time), $\mathrm{d}S$ a differential of surface element of the well-formation interface, and $\mathbf{n}$ is a unit vector (pointing into the well-bore) normal to the boundary surface S. According to the Fourier law for an isotropic solid the *heat flux density vector* $\mathbf{j}$ is proportional to the gradient of the temperature field,

$$\mathbf{j} = -k \nabla T \, , \tag{2}$$

where k is the in general temperature dependent *thermal conductivity* of the rock. Anisotropy effects are common for rocks and therefore the thermal conductivity is in fact a tensor. The anisotropy in rocks manifests at both microscopic and macroscopic scales. As rocks are polycrystalline aggregates of individual minerals, their thermal conductivity are determined by the conductivities of the mineral constituents. Micro-anisotropy is related to the arrangement of the mineral particles and averages to zero on large samples. Macro-anisotropy occurs in large rock volumes due to bedding. For a rock formation the principal directions of the thermal conductivity tensor are (i) the perpendicular to the plane of bedding ("vertical"), and (ii) two arbitrary directions orthogonal to each other and parallel to the ("horizontal") plane of bedding. Consistently with other approximations made throughout we shall neglect in the present analysis the anisotropy of the formation[2]. Eq.(2) is a constitutive relation, i.e., k is a physical property of the substance concerned. Therefore k is both temperature dependent as well as position dependent in a heterogeneous solid.

2.1 Energy balance in the primary loop

In the primary loop subsystem electric power is consumed by the pump at a constant rate. The pump converts this electrical power into mechanical power w with relatively high efficiency η_{pump}. For steady fluid-flow conditions there is no gain of kinetic energy in the flow. If we assume equal height for the inlet and outlet of the primary loop the potential energy of the fluid remains also unchanged. Under these conditions, the mechanical power w delivered by the

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[2] For an anisotropic large sample of rock with two principal directions, the Fourier law given by Eq.(2) reads:

$$\mathbf{j} = -\left(k_{\mathrm{V}} \, (\hat{\mathbf{Z}} \cdot \nabla T)\hat{\mathbf{Z}} + k_{\mathrm{H}} \, (\hat{\mathbf{Z}} \times \nabla T) \times \hat{\mathbf{Z}} \right) ,$$

where $\hat{\mathbf{Z}}$ is a unit vector perpendicular to the plane of bedding. k_{H} and k_{V} are the horizontal and vertical (or parallel and perpendicular to the plane of bedding) principal components of the thermal conductivity tensor respectively. The *anisotropy factor* $k_{\mathrm{H}} / k_{\mathrm{V}}$ has typical values close to one within at most 10% for chalk at 3.5km deep in the North Sea basin as shown later in Table 4.1.

pump to drive the flow is completely dissipated as heat because of the internal viscous forces in the fluid. The bulk temperature of the fluid at the outlet $T_{b,out} > T_{b,in}$ is determined by both (a) the geothermal heat power q extracted from the formation , and (b) the dissipated heat power due to internal friction in the fluid. From momentum balance considerations the dissipated heat power is in magnitude equal to w. The rate of change of the internal energy e of the injection fluid is therefore equal to the geothermal heat power q extracted from the formation plus the mechanical power w delivered by the pump, according to first law of thermodynamics.

The total heat power available for conversion to electrical power in the secondary loop is equal to the rate of change of internal energy e of the injection fluid in the primary loop. However, when coming to economical considerations the geothermal heat power q has greater interest[3]. Certainly, the *net heat power* produced in the primary loop is equal to the difference between the rate of change of internal energy (gain term) and the electrical power consumed (loss term). Subtracting the electrical power consumed by the pump from the total heat power e available for conversion in the secondary loop, the net heat power produced is

$$\text{Net power produced:} \quad e - w/\eta_{\text{pump}} = q + w(1 - 1/\eta_{\text{pump}}) \leq q \tag{3}$$

where the last inequality follows from $\eta_{\text{pump}} \leq 1$.

In short, the *geothermal heat power q* is an upper bound to the *net thermal power produced.* The efficiency of the conversion process from thermal to electric power is restricted by the second law of thermodynamics and other losses, as discussed later in the second part of this report. In any case, the geothermal heat power q is clearly a very relevant parameter when designing or evaluating a geothermal plant using the ELI concept.

2.2 Heat transfer in the formation

The heat transfer analysis in the formation is twofold. On the one hand, in order to estimate the rate at which heat is extracted we need to know the spatial distribution of temperatures in the region close to the wells. On the other hand, to estimate the economical lifetime of the geothermal plant, i.e., the time it takes before the geothermal heat power falls below economically acceptable values, it is important to know the time evolution of q. The geothermal heat power q is not constant in time. Since typical values of the natural heat flux are low compared to the desirable energy production rate, the plant taps thermal energy from the formation much faster than the natural equilibration process mediated by heat conduction. As a result the formation gets cooler with time and the geothermal resources will be depleted

[3] Even if the primary loop were thermally isolated so that q=0, the work w done against internal friction forces would result in a temperature increase of the fluid ($e \neq 0$). Although this heat could be used to drive a turbine, it would be a very impractical and expensive way of generating electricity. The goal in a geothermal plant must be to keep the value of w at a minimum while maximizing the heat power q extracted from the formation.

in that region. In short, the knowledge of the temperature field $T(\mathbf{r},t)$ at every point $\mathbf{r}$ in the vicinity of the well-bore and for all times t is required to design/evaluate the viability of a geothermal plant.

To derive the relevant equations we consider the energy balance (first law of thermodynamics) for a fixed *control volume* (CV) of the solid formation. The rate of variation of the internal energy inside the CV is due to the flux of heat through the *control surface* (CS) enclosing that volume. Expressing the change of internal energy in the formation in terms of the heat capacity per unit mass of the rock c and the temperature variation at a given point,

$$\iiint_{CV} \rho c \frac{\partial T}{\partial t} dV = -\oint\!\!\oint_{CS} \mathbf{j} \cdot \mathbf{n}\, dS \tag{4}$$

where ρ is the density of the rock, dV is a differential of the control volume, dS a differential of area of the control surface, and $\mathbf{n}$ is a unit vector (outward) normal to the control surface CS. In writing Eq.(4) we have assumed that there are not heat production sources in the rock as it could be the case for a radioactive geological formation.

It is always possible to rewrite the total heat flux through the CS [the l.h.s. in Eq.(4)] as a volume integral of the divergence of $\mathbf{j}$ by using the Gauss theorem. If in addition one considers an infinitesimal volume instead of a finite one, the energy balance equation (4) reads

$$\rho\, c \frac{\partial T}{\partial t} = \nabla(k\, \nabla T)\ , \quad \text{for all } \mathbf{r} \text{ in the solid when } t > 0. \tag{5}$$

This is the *heat conduction equation* one needs to solve for the temperature field in the solid formation. The physical properties of the formation ρ, c and k are in general functions of the position and of the unknown temperature field.

To completely define the problem one needs to supplement the partial differential equation (5) with the appropriate boundary and initial conditions. In general, we are interested in both the *steady* and the *unsteady* solutions of the Eq.(5). Since the heat conduction equation is parabolic in time the problem is well defined only after specifying (a) an *initial condition* :

$$T(\mathbf{r}, t=0) \;=\; T_0(\mathbf{r}) \quad , \quad \text{for all } \mathbf{r} \text{ in the solid formation} \tag{6}$$

and (b) the *boundary conditions* at the surfaces bounding the solid formation. In our case the boundary conditions of practical interest are of three types:

- Prescribed temperature at a surface S,

$$T(\mathbf{r},t)\big|_{\mathbf{r}\in S} = T_S \ , \quad \text{for all } t > 0 \tag{7a}$$

This is the boundary condition to be applied at the sea bottom where the temperature is uniform and just a few degrees above 0°C. This is the easiest boundary condition to work with. We shall use it at the rock-wellbore interface too to get an approximate solution of Eq.(5).

Actual conditions at the wellbore-rock interface are however better described by the boundary condition given in Eq.(7c) below. Notice that T_S may be in general a function of the coordinates on the surface and/or time.

- *Prescribed heat flux* across the surface,

$$\mathbf{n}\cdot\mathbf{j}(\mathbf{r},t)\big|_{\mathbf{r}\in S} = -\,k\,\mathbf{n}\cdot\nabla T(\mathbf{r},t)\big|_{\mathbf{r}\in S} = j_S\ , \quad \text{for all } t>0 \tag{7b}$$

were **n** is the outward-drawn unit vector normal to the surface S. This is the boundary condition to be prescribed at the basement[4] where the natural heat flow is approximately constant with a magnitude less than 0.1 W/m^2 as mentioned in the introduction. A particular case of the Eq.(7b) corresponds to the *adiabatic* boundary condition, i.e., $j_S = 0$ for a thermally insulated section of the primary loop. Again, the heat flux j_S can be in general a function of the coordinates on the surface S and/or time.

- *Linear heat transfer* across the solid-fluid interface,

$$-\,k\,\mathbf{n}\cdot\nabla T(\mathbf{r},t)\big|_{\mathbf{r}\in S} = h\left(T(\mathbf{r},t)\big|_{\mathbf{r}\in S} - T_\mathrm{b}\right), \quad \text{for all } t>0. \tag{7c}$$

The outward heat flux density across the boundary surface S is proportional to the difference between the temperature of the solid at the surface and the bulk temperature T_b of the fluid in contact with the solid. Eq.(7c) is also known as the *Newton's law of cooling*. This is the boundary condition one must use for free or forced convection problems. S is the solid-fluid interface and T_b is the temperature of the fluid "far away" from the wall[5], and the constant h is known as the *convection heat transfer coefficient* or *convection surface conductance*. The physics behind the Newton's cooling law is far beyond the scope of this report and we refer the reader to specialized references (Bird et. al. 1960, White 1991, Kreith and Black 1980) for more details. Lastly, we note in passing that the boundary condition (7c) reduces to the *prescribed surface temperature* boundary condition (7a) when h is infinitely large, provided that we identify T_b with T_S, and to the adiabatic boundary condition when h is set to zero.

An accurate calculation of the instantaneous geothermal heat power $q(t)$ for a particular geothermal installation using the ELI concept calls for a numerical treatment of the general heat conduction problem described by Eqs.(5)-(7) for a complex geometry. Such a numerical analysis requires a good deal of well survey data, casing data and geological data as input. Although not impossible, an exact treatment would be only justified if a preliminary, and therefore cruder, estimation has led to economically attractive results. In the following we shall relax some of the complexities of the exact treatment described above to get a rough

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[4] By *basement* geologists refer to the transition between the crust and the sedimentary basin.

[5] For pipe flow the bulk temperature T_b , also called the *mixing cup temperature*, is the velocity weighted average over the cross section of the pipe. Both the bulk temperature of the fluid and the temperature at the wall of the pipe varies in general along the pipe axial direction.

estimation of the geothermal heat power and temperature field in the vicinity of the geothermal well.

3 Primary loop model

We model the primary loop of the geothermal installation using the ELI concept made up of two vertical wellbores of length L_V linked together by a horizontal section of length L_H at depth L_V under the sea-bed. We also assume the well to have a circular cross section of diameter $D=2a$. In this way we neglect the small corrections due to a particular orientation of the wells as we expect them to not significantly alter the main conclusions. Casing and cementing of the wellbore are to be taken into account after solving this simplified model [see Eq.(17) and (18)].

3.1 Main Simplifications

In order to solve our model let us discuss some facts which lead to an approximate treatment. These facts simplify enormously the heat transfer analysis while preserving at the same time the main features of the original problem.

3.1.1 Constant physical properties

The most direct simplification of the Eq.(5) governing the temperature field consist in assuming constant thermal properties of the formation, i.e, we shall neglect the temperature and position dependence of the density ρ, thermal conductivity k and specific heat c of the rock. In this way we avoid the complexities associated with solving the non-linear Eq.(5) which reduces to the much simpler linear *diffusion equation*:

$$\frac{\partial T}{\partial t} = \alpha \nabla^2 T \ . \tag{8}$$

The constant $\alpha = k/\rho c$ is the thermal diffusivity of the rock. Based on dimensional arguments we realize from Eq.(8) that any temperature change diffuses in the formation a distance $L_{\text{diff}} \approx (\alpha t)^{1/2}$. The order of magnitude for typical values of the thermal diffusivity in rocks 3.5 km deep in the North Sea basin are $\alpha \sim 10^{-6} m^2/s$. Hence temperature changes produced at a distance of 1m, 10m and 50m apart are "felt" after 10 days, 3 years and 80 years respectively. Within such short distances the formation can be considered homogeneous and the thermal properties of the rock treated as position independent within a given layer of rock type. Concerning the temperature dependence, one does not need to consider changes in the thermal properties of the rock unless large temperature gradients are built up. We note in passing that the temperature variation due to the natural geothermal gradient of 0.03-0.04°C/m does not significantly affect the thermal properties within those distances either. In summary, the assumption of a homogeneous layered solid with *constant thermal properties* implicit in the rough estimation above is therefore completely justified.

Due to the low typical values of the thermal diffusivity in rocks, the temperature field in the formation never reaches a steady state in the region where thermal energy is depleted. This is at least true within the expected lifetime of some few decades for the geothermal plant. We shall therefore consider a transient situation and hence look for unsteady solutions of the heat diffusion equation.

3.1.2 Horizontal bedding planes

We do not expect the present tectonic dip and strike for the different geological layers of a specific region to alter the physics of the heat transfer. Therefore we consider in our model a horizontal sea-bed and horizontal bedding planes for the geological formation under consideration. If we denote by Z the true vertical height measured from the sea bottom, the initial temperature is a piece-wise linear function of Z. The initial condition (6a) reads $T(\mathbf{r},t=0)=T_0(Z)$ where $T_0(Z)$ is the solution of the heat equation for a multilayered slab in the formation with prescribed temperature at the sea-bed and constant geothermal gradient at the basement.

3.1.3 Border and size effects

Typical values for the diameter D of the geothermal well are in the range of 10-40 cm (5" to 15") certainly much smaller than the typical values for L_H and L_V . The cylindrical surfaces can be considered as infinitely long and hence we neglect *border* and *size effects* due to the large curvature at the comparatively short bends of the wellbore.

3.2 Solution of the model

With the reasonable approximations just discussed we can easily solve the temperature field $T(\mathbf{r},t)$ close to the geothermal well and from it the geothermal heat power $q(t)$ via Eqs.(1) and (2). Due to the symmetry of our model it is obviously convenient to introduce standard cylindrical coordinates (r,ϕ,z) with z denoting the axial direction of the well[6], r being the radial distance to the well axis, and ϕ the angular coordinate about the same axis.

The initial temperature is still a function of z only in the vertical sections of the primary loop. Given the small value of the geothermal gradient one can safely neglect the temperature variations around the perimeter of the well ($r=a$, $0<\phi<2\pi$) in the horizontal section of the loop. As a result the initial condition for the heat conduction equation is

$$T(\mathrm{r},t=0) = T_0(z) \quad , \tag{9}$$

[6] It is also called the *measured depth* along the well axis

i.e., the initial temperature is at most a piece-wise linear function of the z coordinate in the region close to the well. This is so because any two stations z_1 and z_2 of the well are "far" away from each other in thermal terms, due to the low thermal diffusivity of the rock. As discussed above, any radial distance larger than 50 m works as an "infinite" radial distance within the lifetime of the geothermal plant. For the same reason, the z coordinate behaves as a Cartesian coordinate. This allows us to replace the boundary condition of constant flux at the basement (Z large and negative) by a prescribed temperature far away from the well

$$T(\mathbf{r},t>0)\big|_{r\to\infty} = T_0(z) \quad , \tag{10}$$

For the geometry considered the external normal **n** to the formation is the negative radial unit vector. Thus the convection boundary condition (7c) reads

$$k\left.\frac{\partial T}{\partial r}\right|_{r=a} = h\left(T|_{r=a} - T_b\right), \quad \text{for all } t>0 \tag{11}$$

which is also only a function of the z coordinate.

Looking at Eqs.(8)-(11) we have managed to transform the original complex well geometry to a much simpler cylindrical one. Moreover, since the initial and boundary conditions are independent of ϕ , the temperature will be a function of r, z and t only. We can thus eliminate all ϕ dependencies in solving the heat diffusion equation (8) in cylindrical coordinates, subject to the z-dependent conditions (9)-(11). Once the temperature field is known we can evaluate the *geothermal heat power per unit length*:

$$\frac{\mathrm{d}q}{\mathrm{d}z} = (2\pi a)k\left.\frac{\partial T}{\partial r}\right|_{r=a}, \quad \text{for all } t>0 \tag{12}$$

where, based on the cylindrical geometry we have written the surface element as $\mathrm{d}S=2\pi a\mathrm{d}z$.

We see from Eq.(12) that in order to evaluate the geothermal heat power we do not need to solve the temperature field for all r but only for values of r close to $r=a$. Let us for a moment neglect the z dependence in the differential equation. We shall therefore proceed to solve the unsteady radial conduction equation:

$$\frac{\partial T}{\partial t} = \frac{\alpha}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right), \quad \text{for } r>a \text{ when } t>0 \tag{13}$$

subject to the boundary conditions (9) - (11) as if they were independent of z. With such an approximation we gain physical insight as we avoid unnecessary technicalities related to the way of exactly solving the problem. Instead of solving the unsteady equation (13) for the semi-infinite domain $r>a$ subject to the boundary condition (10), we solve its time independent (and therefore simpler) version (the Laplace equation) in the finite region $a<r<R_\infty(t)$ with a prescribed temperature boundary condition $T(r=R_\infty)=T_0$. The time

dependence is approximately taken into account through letting R_∞ be a time dependent function. This is the so called quasi-steady approximation. The justification underlying this approximation can be directly read off the diffusion equation (5): After a time t, we expect all the points inside a hollow cylindrical volume with outer radius

$$R_\infty(t) = a + \sqrt{C\alpha\, t} \quad , \tag{14}$$

to reach the steady state. In (14) C is a constant of the order of unity. Notice that the exact dependence of the temperature field outside the radius R_∞ is of no interest for the evaluation of the geothermal heat power q determined from the temperature field close to the well of radius $a << R_\infty$ at large times.

From the inspection of local expansions of known exact solutions of the heat conduction equation (Carslaw and Jaeger 1959), one finds the value of C to be "geometry" dependent: It is $C = \pi = 3.1415...$ for the plane geometry, while $C=4e^{-2\gamma} \cong 1.2609...$ for a cylindrical geometry, being $\gamma = 0.5772...$ the Euler constant. In our model and at short times $t<a^2/\alpha$, the thickness of the "steady state" region is small and the cylindrical boundary well-rock interface looks like plane in the region where the approximation is valid; for the shortest times one should then use $C = \pi$. At longer times ($t > a^2/\alpha$) the "cylindrical" value of $C = 4e^{-2\gamma}$ must be used instead. For typical values of the parameters involved the time scale $\tau_a = a^2/\alpha$ separating the short and long time behavior is of the order of just a few days. For all practical purposes we are therefore interested in the long-time behavior of the quasi-steady approximation.

The temperature distribution in the formation within this approximation is valid for the region $a < r < R_\infty(t)$ and is equal to:

$$T(\mathbf{r},t) \approx T_0 + \frac{T_0 - T_b}{(k/ha) + \ln[R_\infty(t)/a]} \ln[R_\infty(t)/r] \quad . \tag{15}$$

According to Eq.(2.12) the heat power per unit length (dq/dz) transferred to the fluid is, within the same approximation, equal to

$$\left(\frac{dq}{dz}\right) = (2\pi a)\ \frac{(T_0 - T_b)}{(1/h) + \frac{a}{k}\ln[R_\infty(t)/a]} \quad , \tag{16a}$$

$$\left(\frac{dq}{dz}\right) \approx \begin{cases} (2\pi a)\ \dfrac{2k(T_0 - T_b)/a}{(2k/ha) + \ln(4\alpha t/a^2) - 2\gamma} & \text{for } t \geq a^2/\alpha \\[2ex] (2\pi a)\ \dfrac{(T_0 - T_b)}{(k/ha) + \sqrt{\pi\alpha t/a^2}} & \text{for } t \leq a^2/\alpha \end{cases} \tag{16b}$$

We have checked the validity of the quasi-steady approximation for both the temperature field close to the well given and the heat power by comparing Eqs.(15) and (16) with the asymptotic short- and long-time expansions of the exact results quoted in (Carslaw and Jaeger, 1959) for (i) the cylindrical geometry with $h = \infty$ and (ii) for the plane geometry and arbitrary values of h. We then find the quasi-steady approximation very accurate behaving as an asymptotic matched expansion to the short- and the long-time limit of the exact solution.

Using similar arguments we can approximately describe the z dependence of the temperature field and the heat flux by substituting both T_0 and T_b by their z-dependent values in Eq.(15) and (16). This is a good approximation provided that the second derivatives of the temperature field with respect to z are negligible, i.e., for an almost linear variation of the temperature along the same direction. This linear temperature variation is on the other hand obtained in the exact solution for infinitely long pipes under steady conditions and far away from the inlet point (Bird et al., 1950).

Eq.(16a) is reminiscent of steady heat conduction problems where the heat flux is written as the surface area through which heat is conducted, times the ratio of the over-all temperature difference (T_0 - T_b) to the thermal resistance of the system. From Eq.(16b) we "read" the convection thermal resistance $1/h$ (the inverse of the surface conductance) in series with the conduction thermal resistance for the hollow cylinder of rock with inner and outer radius a and $R_\infty(t)$ respectively. This interpretation allows us to easily incorporate into our model the additional thermal resistance due to the casing and cement between the fluid and the rock. When casing and cementing are taken into account the total effective thermal resistance (based on the wellbore radius a) is then:

$$(a/k) \ln (R_\infty(t)/a) + (a/k_{cem}) \ln (a/R_o) + (a/k_{casing}) \ln (R_o/R_i) + 1/h \quad , \tag{17}$$

where R_o and R_i are the outer and inner radii of the casing respectively, k_{casing} and k_{cem} are the thermal conductivities of the casing and the cement respectively. The geothermal heat power per unit length taking into account the additional thermal resistances of casing and cementing is,

$$\left(\frac{\mathrm{d}q}{\mathrm{d}z}\right)(z,t) \approx (2\pi a) \frac{k\left[T_0(z) - T_b(z,t)\right]/a}{\frac{1}{2}\ln\left(1.26 \cdot t/\tau_a\right) + \frac{k}{k_{cem}}\ln\left(a/R_o\right) + \frac{k}{k_{casing}}\ln\left(R_o/R_i\right) + \frac{k}{ha}} \quad , \tag{18}$$

From Eq.(18) we see the transient thermal resistance of the formation to grow with time while the geothermal plant is in service. After a fixed time this will be the most significant contribution to the effective thermal resistance limiting the extraction of heat from the formation.

The value of h is related to the physical properties of the fluid which in turn are a function of the bulk temperature of the fluid $T_b(z)$ (Bird et al. 1960). The remaining terms can be easily calculated for a specific well.

The total geothermal heat power can be obtained by integrating Eq.(18) along the "well" coordinate z. The unknown bulk temperature T_b (z) of the fluid is solved simultaneously by considering the first law of thermodynamics $e = q + w$ for the fluid in differential form. The heat power transferred from the formation between z and z+dz plus the internal dissipation of the flow cause the increase of the bulk temperature of the fluid in the same section:

$$mc_f \frac{dT_b}{dz} = \frac{dq}{dz} + \Phi \quad , \tag{19}$$

where m is the mass flow rate in the well and c_f is the heat capacity per unit mass of the fluid and Φ = dw/dz is the power dissipated per unit length dz. As discussed before one would expect the Φ term much smaller than the heat flux term in an effective heat transfer process. We note that Φ is also z dependent through the temperature dependence of the viscosity of the fluid. In any case the ordinary differential equation Eq.(19) must be integrated numerically with the initial condition T_b $(z= z_{in}) = T_{b,in}$ at the inlet of the injection well up to $z = z_{out}$ at the outlet. As a result one gets the rate of change of internal energy of the injection fluid in the primary loop

$$e = m\, c_f\, [\, T_{b,out} - T_{b,in}] \; = q(t) + w \tag{20}$$

where we have neglected the small variations of the fluid specific heat c_f with temperature.

3.3 Upper bound for the geothermal heat power

From inspection of Eq.(18) we can estimate an upper bound to the geothermal heat power $q(t)$ very easily by noticing that:

(i) The geothermal heat power is maximum when the numerator in Eq.(18) is maximum:

$$k\,(T_0 - T_b\,) < k_{max}\;[\;(T_0)_{max} - (T_b)_{min}\;] = k(Z= -L_V)\;\;[\,T_0\,(Z= -L_V) - T_{b,in}\,]$$

were we have used the fact that the rock thermal conductivity increases with the depth and therefore is maximum at maximum depth of the formation, the temperature of the fluid is always higher than at the inlet point, and the initial temperature T_0 is maximum at the deepest location because of the natural geothermal gradient.

(ii) The geothermal heat power is maximum when the convection heat transfer coefficient h is maximum, ideally infinite.

(iii) The geothermal heat power is maximum when the thermal resistance of casing and cement are minimal , ideally zero both of them.

The upper bound to the total geothermal heat power can be then expressed as

$$\left(\frac{\mathrm{d}q}{\mathrm{d}z}\right)_{\max} \approx 4\pi k_{\max} \frac{T_{0,\max} - T_{\mathrm{b,in}}}{\ln(1.26 \cdot t / \tau_a)} \quad . \tag{21}$$

An upper bound to the integrated geothermal heat power is obtained by multiplying this value with the length of the primary loop in thermal contact with the formation:

$$(q)_{\max} \approx 4\pi k_{\max} \frac{T_{0,\max} - T_{\mathrm{b,in}}}{\ln(1.26 \cdot t / \tau_a)} L_{\mathrm{thermal}} \quad . \tag{22}$$

3.4 Numerical results

Using typical values for a geothermal plant offshore located in the North Sea we can now calculate the maximum geothermal heat power per unit length along the well using Eq.(21). For this purpose we only need to specify: the typical diameter D of the well, the thermal properties of the formation (α and $k_{\max}$), and the maximum temperature difference between the formation and the injection fluid ($T_{0,\max}$ - $T_{\mathrm{b,in}}$). This upper bound estimate $(q)_{\max}$ for the geothermal heat power requires the specification of a relatively modest number of parameters compared to the input data needed to obtain the exact value for q via a more detailed and computationally expensive numerical treatment.

Sample	Depth [m]	Porosity	Measured Thermal Conductivity [W / (m °C)]	
			k_H	k_V
A	3400	35	1.66	1.72
B	3400	36	1.72	1.70
C	3500	25	2.06	1.89
D	3500	10	2.53	2.32
E	3500	12	2.56	2.56
F	3500	12	2.64	2.44

Table 3.1. Physical properties of a chalk formation at accessible depth in the North Sea. Data provided by E. Prestholm (RF-Rogaland research database). Both the mass density and specific heat (or heat capacity per unit mass) of all the samples is approximately the same: ρ = 2670 kg/m^3 (2.67 g/cm^3), $cl_{\text{at } 50^{\circ}\mathrm{C}}$ = 895 J/(kg °C) (0.214 cal/(g °C)) , and α = 1.054 10-6 m^2/s (10.54 cm^2/s).

We consider as the primary loop two vertical wells 3 km long linked together with a horizontal section 5 km long, yielding a maximum thermal length of 11 km. To estimate the influence of the diameter of the well in the results we allow D=2a to take values between 5" and 15". Typical values for the physical properties of the rock formation are given in the table below. These values correspond to *wet* samples taken from the North Sea at a depth of 3400-3500 m. The anisotropy of the rock (chalk formation) is in all cases below 10% and we shall therefore neglect the anisotropy of the formation in calculating the upper bound for the geothermal heat power q. We read from the table a maximum value for the thermal conductivity $(k)_{max} = 2.64$ W/(m°C).

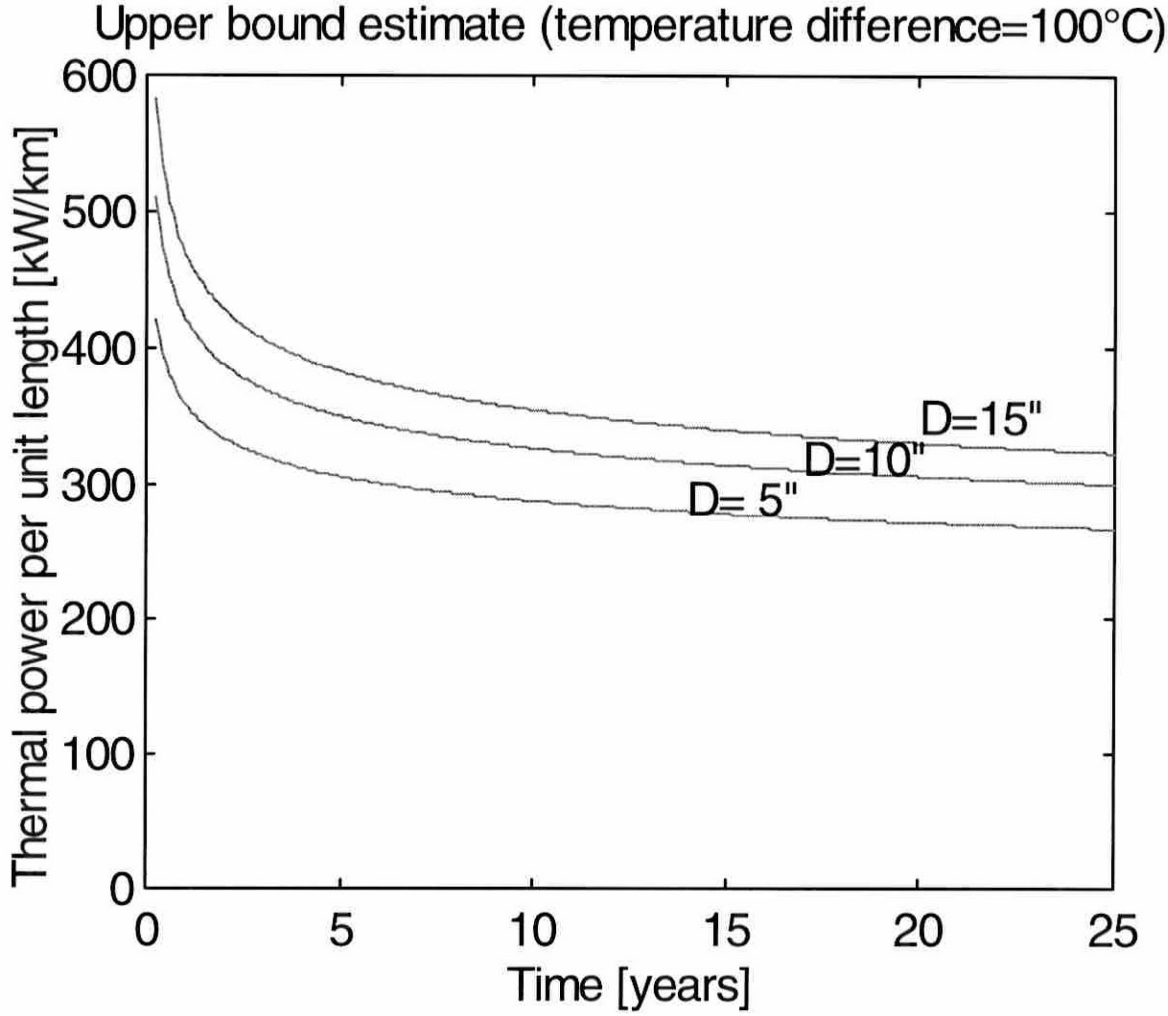

Figure 1 The upper bound estimate for the instantaneous geothermal heat power per unit length along the well as a function of time using Eq.(21). The different curves show the results for three different values of the diameter: D=5", 10" and 15" as indicated in the plot. The thermal diffusivity of the formation is assumed to be $\alpha=1.05\ 10^{-6}$ m^2/s and for the thermal conductivity we use $(k)_{max}$=2.64W/(m°C). The temperature difference between the fluid and the formation is assumed to be 100 °C.

At depths of 3-3.5 km in the North Sea, measured[7] formation temperatures are in the range 100°C to 120°C so we adopt here $(T_0)_{max}$ = 115°C. Using water as the injection fluid requires a slight pressurization of the flow. We consider the bulk temperature of the fluid at the inlet of the primary loop flow at $T_{b,in}$ = 15°C = $(T_b)_{min}$ giving a maximum temperature difference between the fluid and the formation of 100°C.

Inserting these numerical values into Eq.(21) gives an upper bound for geothermal heat power density (per unit length along the well) dq/dz as shown in Figure 1.

From this figure we read a maximum geothermal power of approximately 350 kW/km for a D=10" well diameter and average temperature difference between the injection fluid and the formation of 100 °C, after 5 years of service. The maximum geothermal power reduces to 175 kW/km when the temperature difference is 50 °C while the other parameters remain the same.

4 Cost model

In order to estimate the costs of the geothermal electric power produced by the ELI - concept, a simple cost function is derived. The costs can be divided into fixed costs C_f, and variable costs C_v, listed respectively in Tables 4.1 and 4.2 below.

Cost component;	Description:
Drilling and completion	The costs for drilling a loop between the selected wells, running casing and completing the well ready for geothermal extraction.
Surface installations	Purchase and installation of heat converters, electric generators, control systems for the process system on the platform.
Power distribution	Establish a power distribution network for the electric energy produced on the platform.
Other fixed costs	Fixed costs related to platform rebuilding, land base installation and other costs not mentioned above.

Table 4.1. Components of the fixed costs C_f.

[7] Data provided by Philips Petroleum, Norway.

Cost component;	Description:
Maintenance of platform	Regular control, repair and corrosion protection of the platform in order to maintain safety for the people who work on the platform and protect the platform for maximum safe total life.
Maintenance of process equipment	Regular maintenance for adjustments and optimization of the process equipment to ensure safe and efficient operations.
Process control	Continuous control of the process, including the required manning of the platform and the land based installations.
Other variable costs	Variable costs related to insurance, transportation and other costs not mentioned above.

Table 4.2. Components of the variable costs C_V.

The fixed costs C_f and the variable costs C_V are both a sum of their respective components. The cost C_{kWh} for produced electricity by the geothermal electric plant can be calculated by the following equation (i.e. cost per kilowatt hour produced electricity):

$$C_{kWh} = \frac{C_f + C_v \cdot R}{P \cdot 8760 \cdot r \cdot R} \tag{23}$$

where P is the total power production of the power plant (in kW), 8760 is the number of hours in a year, r is the average fraction of time the installation is producing, and R is the capitalization factor for n years of lifetime, with an interest rate of p percent.

$$R = \sum_{i=1}^{n} (1 + p/100)^{-i} = \frac{100}{p}\left[1 - \frac{1}{(1+p/100)^n}\right] \tag{24}$$

which for $p = 7\%$ and n = 25 gives $R = 11.65$.

4.1 Evaluation of the cost function

Since the ELI concept is based on utilizing an existing offshore installation, and since many factors are unknown for a general case, the costs would attain a large range of values. The conditions shown in Tables 4.3 and 4.4 have been used as input to Eq.(23) to estimate a range for the cost of produced electricity. The number of loops required to generate 5000 kW_e is estimated from the following assumptions: 11 km long loops, an average heating power of 175 kW_t/km and an energy conversion efficiency of 7.5 %. The latter figure corresponds to the upper bound for geothermal heat power after 5 years for a pipe with D = 10", and an initial temperature difference of 50 °C. The latter corresponds to an upper bound estimate if the temperature of the return fluid from the power plant is 54 °C, as in the base case of the study by SINTEF. It also a reasonable estimate for the average (along the pipe) temperature difference if the return temperature is close to ambient temperatures.

Assumed lifetime (years) n:	25
Assumed annual interest p:	7 %
Assumed number of well loops:	35 loops
Average maximum electric power production, P:	5000 kW

Table 4.3. Assumptions on interest, and size and lifetime of plant.

Cost element	Comment:	Cost range [MNOK]
C_f	Drilling and completion, per geothermal well loop	50 - 150
C_f	Surface installations (source: SINTEF)	70 - 110
C_f	Power distribution	5 - 50
C_f	Other fixed costs	5 - 50
C_v	Maintenance of platform, annual costs	2 - 20
C_v	Maintenance of process equipment, annual costs	2 - 20
C_v	Process control, annual costs	5 - 50
C_v	Other variable costs, annual costs	5 - 50

Table 4.4. Assumption on elements of cost function. The range of values indicate estimated uncertainty in values.

Using lower bounds only, and upper bounds only, in the cost function of Eq.(23), we obtain an estimated price as shown in Table 4.5 with r = 1.0 (i.e. continuous production with no downtime).

Assumed fixed costs range:	$1830 < C_f < 5460$ MNOK
Assumed variable costs range:	$14 < C_v < 140$ MNOK/year
Resulting range for the minimum price of the produced electricity	$4 < C_{kWh} < 14$ NOK/kWh

Table 4.5. Assumptions and discussion on the production cost for the electricity.

5 Discussion

We have analyzed the ELI-concept based on geothermal heat extraction from a well in a rock structure with heat transfer dominated by conduction in the body of the formation. A detailed numerical treatment of the heat transfer process for an actual candidate installation would require input data and computational resources not available for this evaluation project. We have therefore considered a simple but realistic model of the primary loop. The model calculation presented here is also accurate enough for our purpose. Using a quasi-steady approximation we have worked out the solution of the model for the time-dependent temperature field close to the geothermal well. The instantaneous geothermal power q has thus been derived from the temperature field. Further consideration of the casing and cementing has been incorporated in the previous expressions.

In order to exactly solve the geothermal power q within the simplified model proposed, one would have to specify the convection heat transfer coefficient h as a function of the z-dependent Prandtl and Reynolds number in the Eqs.(18)-(20) (Bird et al., 1960). We have instead obtained an expression for the maximum heat power q one can extract from the formation [see Eqs.(21) and (22)]. The upper bound estimate presented here is sufficient to economically evaluate the feasibility of the ELI concept in the North Sea. The value obtained for $(q)_{max}$ must be considered as the most favorable or *best case estimate*. In practice, one should expect an even lower value for $(q)_{max}$ due to:

(a)The additional consideration of the thermal resistances of the casing and cementing.

(b) The finite value of h for typical values of the flow rate and of the physical properties of the injection fluid. This can be read off as a non-vanishing convection thermal resistance $1/h$ (see Eq. (17)).

From Eq. (21), the geothermal heat power of the geothermal installation using a closed loop to extract heat is strongly limited by the actual values of (a) the temperature difference between the rock and the injection fluid, and (b) the effective thermal resistance of the formation which grows (logarithmically) with time and is inversely proportional to the thermal conductivity of the rock. We found the heat power extracted from the geothermal loop to decrease with time.

After 5 years of service the maximum power that can be extracted is in the range of 175-200 kW_t per each kilometer along the well. This result follows from considering the initial temperature of the rock 50°C hotter than the fluid, and with a well diameter between 5" and 15" (see Figure 1).

We have also obtained a rough estimate for the cost of electricity produced in the North Sea using the ELI concept in the range of 4 to 14 NOK per kilowatt-hour. The range of values reflect the uncertainties in the cost estimates, whereas the values themselves are based on upper bound estimates for the electricity production capacity. Actual values for the cost of such energy using known technology will therefore be even higher. The main part of the investment costs are connected with drilling and completion of loops. Such costs must be reduced by orders of magnitude in order to make the concept economically attractive for the

North Sea. It has been beyond the scope of this project to take into account potential costs saving associated with postponement of platform abandonment, and positive environmental effects.

Since the present analysis has been limited to upper bound estimates, it is only possible to draw conclusions as to whether the ELI concept *may* be economically viable with current technology, i.e., either a negative conclusion or no conclusion may be drawn. For applications in the North Sea we conclude that the ELI concept is currently not profitable. For applications of the concept in other geographical areas and/or with new technology, a more detailed technical and economical analysis must be conducted.

One could consider placing the geothermal wells in aquifers to improve the heat transfer due to the possible but very unlikely (Bjørlykke et al., 1988) natural convection cells. Our first impression is that typical flow velocities in such convection cells, if they occur, would be too low to significantly contribute to the heat transfer (see footnote 1, page 2). Even assuming that heat transfer might be better, one should (a) first locate the aquifers, and (b) overcome the technological difficulties in completing the geothermal wells in such regions. This would add exploration and drilling costs to the investment which have not been taken into account in the present study. The idea of locating the thermally active geothermal well in specific regions is also beyond the original goal of using improductive or abandoned *existent* wells. Due to budget restrictions we are not in conditions to examine further this alternative.

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Part II

HEAT CONVERSION STUDY

SINTEF

GEOTHERMAL POWER PRODUCTION ON ABANDONED OIL PLATFORMS IN THE NORTH SEA

1 SUMMARY OF PART II

This part of the report presents the results of a study conducted by SINTEF Thermal Energy and Hydropower. The work is a part of a total study for geothermal power production on abandoned platforms in the North Sea based on the electricity by liquid injection (ELI - concept, pat. pend. 950306) in cooperation with Rogalandsforskning (RF).

There are a large number of platforms in the North Sea, and now some of the production fields of oil and gas will be shut down in the near future due to low production and no economical benefit in further operation. The costs of removing the platforms are very huge, and some alternatives to condemnation are very interesting to lay open.

Power production based on geothermal heat is one option for utilization of the platforms. The binary fluid power plant analysed in this report utilise geothermal fluid of a temperature of 110 °C. The total efficiency of the power plant with a condenser at sea level is maximum 7.5 % depending on the power for driving the geothermal fluid. Higher geothermal temperatures will give better efficiencies. A geothermal fluid temperature of 190 °C gives an efficiency at maximum 12 % depending on the power for driving the geothermal fluid and cooling water. The ELI-concept with the geothermal heat extraction with a pipeline in a rock structure with heat transfer dominated by conduction, is shown to be very expensive. A relatively low heat transfer flux into the geothermal fluid in the pipeline require long pipelines and thereby give relatively high power demand for driving the geothermal fluid pumps. The heat transfer between the geothermal source and pipeline in an aquifer, will be considerably higher and lower power demand for driving the geothermal fluid is required.

This study has focused on the ELI concept with a geothermal heat source of 110 °C. There should be carried through a detailed investigation to find the areas with the highest temperatures available in the North Sea basin to increase the efficiency and the economical benefits for geothermal power production. The location of the closed pipeline in the ELI concept is very important for heat recovery. Structures including fluids have to be carefully investigated to find the best heat transfer conditions for geothermal heat utilization.

There are also other interesting alternatives, and especially for utilization of aquifers. Geothermal heat from aquifers can be available at the surface without adding any work to the geothermal fluid due to the high pressures. Some aquifers also contain methane and this component can be separated and used in a conventional fired power plant. Other concept for utilization of abandoned platform can be wind power, wave power and power production based on rest hydrocarbons in depleted wells.

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2 INTRODUCTION

This part of the report presents the results of a study conducted by SINTEF Thermal Energy and Hydropower. The work is a part of a total study for geothermal power production on abandoned platforms in the North Sea based on the electricity by liquid injection (ELI - concept, pat. pend. 950306) in cooperation with Rogalandsforskning (RF). The study is financed by The Research Council of Norway. SINTEF Thermal Energy and Hydropower has studied the power production plant on the platforms, and RF has been studying the utilization of heat in the wells.

There are a large number of platforms in the North Sea, and now some of the production fields of oil and gas will be shut down in the near future due to low production and no economical benefit in further operation. The costs of removing the platforms are very huge, and some alternatives to condemnation are very interesting to lay open. Power production based on geothermal heat is one option for utilization of the platforms.

3 POWER CYCLES

The issues associated with the economical utilization of geothermal energy are extremely complex because geothermal systems are site-specific. The characteristic of the geothermal site must be matched to appropriate energy conversion alternatives. The concept in this study is based on the ELI (Electricity by Liquid Injection) idea, and the concept includes a closed pipeline inside drilled wells for heat recovery. The heat from the wells (ELI-concept) is available at the platform deck as water or steam depending on the pressure and the temperature of the geothermal fluid. The geothermal fluid is defined as the fluid used for heat recovery from the wells. The geothermal fluid inside the pipeline is assumed pure, and no separation or cleaning process is required at the platform deck before utilization of geothermal heat for power production in the power plant.

The power cycles suitable for this purpose can be divided in mainly two categories. Direct use of geothermal fluid in power generation turbines, or binary fluid working cycles which require a heat exchange between the geothermal fluid and the power cycle working fluid. The first system requires relatively high temperatures (160 °C) of the heat source, and the second system with a binary fluid working cycle has potential down to 90 °C for power generation (Skille, 1994). In the next chapter the thermodynamics and different methods for geothermal power production are described.

3.1 Thermodynamic criteria

The second law of thermodynamics imposes stringent limitations on the production of electricity from low temperature geothermal heat sources. The efficiency of the system is very dependent on both heat source temperature and the temperature of the surroundings. The ambient temperature level at platforms offshore is assumed to be the temperature of the sea water. Water-cooled condensers are preferred because they are more efficient and less auxiliary power is needed compared to cooling towers based on use of ambient air. This is the normal situation, but it depends on the altitudes from the condenser to the sea level. The disadvantage of cooling towers based on ambient air is the rise of the temperature level of the air in the summer time. In this study sea water cooled condensers are considered. The temperature is important because it determines at which temperature level the condensing heat can be rejected to the surroundings.

The efficiency of a geothermal power plant is normally related to the amount of heat used versus power production. Efficiency is not expressing the total power production available in the heat, and a thermodynamical analysis of available work (exergy) is very interesting in determining the best power cycle.

3.1.1 Efficiency

A common definition of thermal efficiency in power production cycles is the ratio between real work and the heat added to the power generation process. An efficiency calculation in this way will not take into account how efficient the heat resources are utilised. Different cycle concept will get different efficiencies depending on the return temperature of the geothermal fluid. When a small amount of heat is being extracted form the geothermal fluid, the efficiency will be proportionally great, because the resource is being utilised poorly and the heat is extracted at a relatively high temperature level. This is true because high temperature of the rejected heat is not considered as thermodynamically losses in calculating the efficiency. A comparison on different cycle concept is very difficult to perform in this way, because different return temperatures of the geothermal fluid make changes in the heat energy input into the different power cycles. From this point of view the efficiency will be calculated by referring to the total heat available in the geothermal fluid. The total heat available is defined as the amount of heat from the geothermal fluid at a given temperature down to the dead state (ambient conditions) which is defined at the temperature of 7 °C. The efficiency is expressed in the following equation:

$$\eta = \frac{W_{net}}{Q} \qquad \textbf{Eq. 1}$$

where

η = efficiency

W_{net} = real work

Q = heat available from the geothermal fluid by extraction of heat down to a temperature of 7 °C of the geothermal fluid

The efficiency used in this report refer to this definition, and a comparison of different cycles can be applied for determining the power cycles best suited for geothermal power production at given conditions.

3.1.2 Exergy efficiency

Availability, available work, or exergy are equivalent expressions for the part of a heat source which can be utilised to generate mechanical work. The Carnot efficiency is related to the amount of available work, and it is an expression of the maximum share of the heat which can be converted to mechanical work. The Carnot efficiency is calculated on basis of constant temperature of the heat source. In the ELI- concept the temperature of the geothermal fluid is reduced in the heat exchanging process with the power cycle working fluid, and a maximum thermal efficiency can be calculated considering the cooling of the geothermal fluid into ambient temperature. In Figure 1 the Carnot efficiency and the maximum thermal efficiency are plotted as function of the heat source temperature, and it is obvious that the temperature of the heat source is of great importance. Practical applications have loss of available work in both heat exchanging processes and mechanical processes related to power production from heat sources, and the real efficiencies of power plant based on the ELI-concept will be lower than the maximum thermal efficiency.

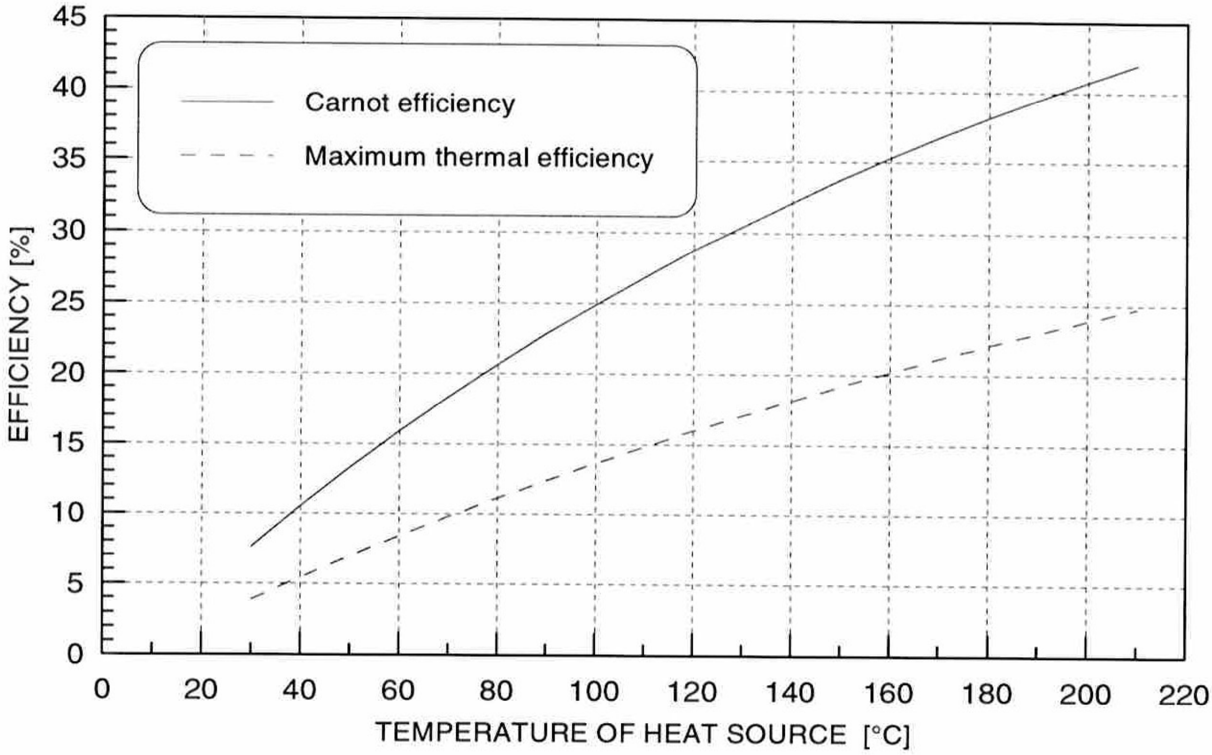

Figure 1 Carnot efficiency and maximum thermal efficiency as function of temperature of the geothermal fluid. The ambient temperature is 7 °C.

The available work (ΔB) in a process can be expressed as the following function:

$$\Delta B = m\left(c_p(T_1 - T_0) - T_0\left(c_p \ln\frac{T_1}{T_0} - R\ln\frac{p_1}{p_0}\right)\right) \qquad \textbf{Eq. 2}$$

where

T_1 = temperature of the geothermal heat

p_1 = pressure of geothermal heat

T_0 = temperature of the surroundings

p_0 = pressure of the surroundings

m = geothermal fluid flow rate

c_p = geothermal fluid heat capacity

R = gas constant

An approach for determining the utilization of the geothermal heat would be to compare directly the real work to the maximum available work (exergy) ΔB by defining an efficiency due to available work called exergy efficiency η_u as follows:

$$\eta_u = \frac{W_{net}}{\Delta B} \qquad \textbf{Eq. 3}$$

η_u = exergy efficiency

W_{net} = real work

ΔB = available work in the geothermal fluid

The exergy efficiency indicates in a very powerful way the goodness of the power cycle, but it says little about the total amount of heat in the process. Exergy is also a sort of academically property, and the efficiency is a more familiar expression for describing the goodness of power cycles.

3.2 Direct-use cycles

Direct use cycle is a common term for geothermal power production application using the geothermal fluid directly in the power generating process, and there exist a lot of different "direct use power cycles" of geothermal fluid for power cycle applications. Different cycle concepts are adopted depending on the purity and the share of water/steam in the geothermal fluid. Common concepts are:

- Straight condensing cycles
- Non-condensing direct-use cycles
- Flash cycles

Straight condensing cycles can use the geothermal fluid directly in steam turbines after separation of steam and water. Saturated steam with the inert gases expands in the steam turbine, and downstream the steam turbine the geothermal fluid is condensed in a condenser at low pressure (below atmospheric pressure). The geothermal water is then reinjected to the aquifer by a pump. An aquifer is an amount of water often including hydrocarbons like methane and minerals. These aquifers are often trapped in formations of impermeable sediments and they can be very huge. The temperature of the aquifers will be site specific. The inert gases or the noncondensable gases in the geothermal fluid are separated in the condenser and boosted to atmospheric pressure where they are rejected. In geothermal fluids with high contents of inert gases the noncondensing direct-use cycles are preferred. Condensing direct-use cycles are preferred due to thermodynamic efficiency for power cycles with geothermal fluids with inert gases in the range of 20 to 25 % of steam content by weight (Marconi et. Al 1982).

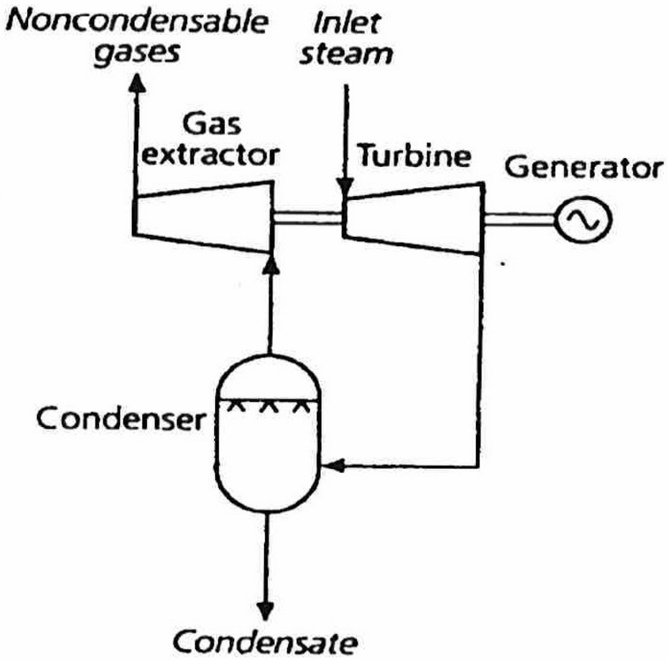

Figure 2 Direct-use cycle; dry-steam condensing turbine with compressor for noncondensable gas removal

Noncondensing direct-use cycles for steam dominated geothermal systems are very simple, and they have advantages for geothermal fluids including noncondensable gases (inert gas). The output from the turbine is directly rejected to the atmosphere, and no vacuum compressor is needed to extract the noncondensing gases.

Flash cycles are common in wells producing both hot water and steam as geothermal fluid. Energy can be extracted from the hot water phase by flashing it into a lower pressure vessel and using the steam produced in a steam turbine. More than two flash steps seems not to be economical, and flashing at pressures below atmospheric pressure leads to very huge equipment because of low specific weight (density) of steam. In vacuum systems it is also possibilities for ambient air to impose the system and methods for avoiding this are required.

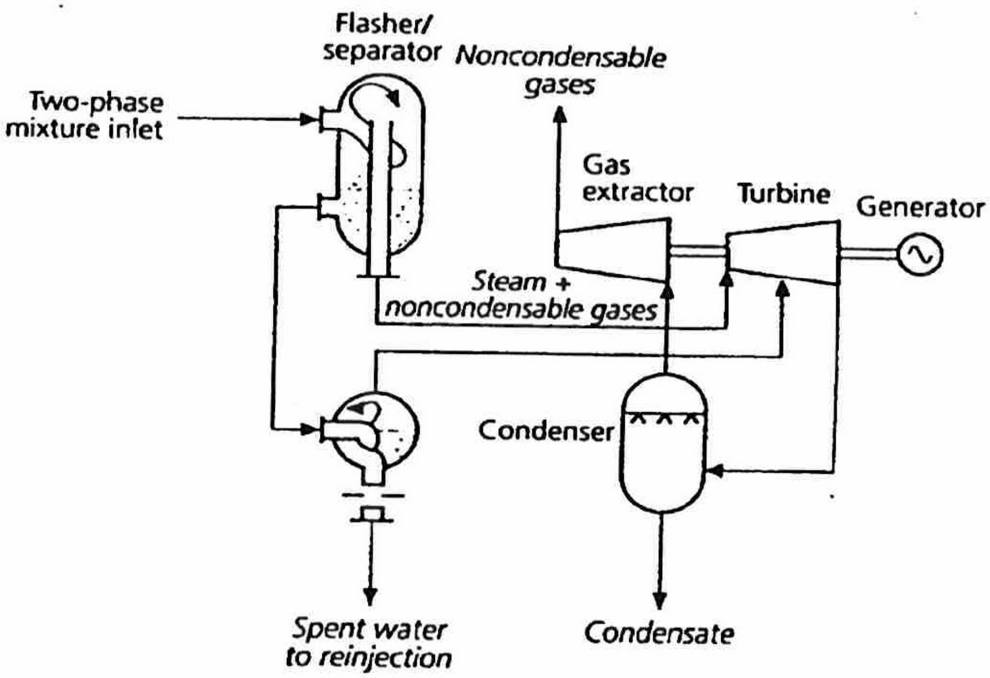

Figure 3 Direct-use cycle; double flash condensing turbine with compressor for noncondensable gas removal. The second flash step adds saturated steam to the turbine at a lower pressure than the first step flash.

The concept of direct-use cycles has to be considered for the ELI-concept with high temperatures (> 180 °C), but is beyond scope of this work. The geothermal fluid in the ELI-concept could be pure water/steam, and direct cycles with no inert gas handling can be used.

3.3 Binary fluid cycles

Binary fluid cycles consist of two working fluids as the name expresses. The heat of the geothermal fluid is utilised by heat exchange with a working fluid with low boiling point such as freons, hydrocarbons, water and ammonia in a Rankine cycle. Binary fluid cycles are preferred in geothermal power plants with low temperature of the geothermal fluid. Temperatures down to 90 °C are possible but higher temperatures give better advantages due to power plant efficiency. The advantage of binary fluid cycles compared to direct-use cycles is measurable up to about 180 °C, but for geothermal fluids with higher temperatures the use of direct-use cycles must be considered. A sketch of a binary fluid cycle is shown Figure 4. The geothermal fluid flows through a heat exchanger vaporising the working fluid in the Rankine cycle. After the vaporising process the working fluid is superheated by heat from the geothermal fluid before entering the turbine for mechanical work generation. Next to the expansion process the working fluid is condensed in the condenser, and heat is rejected to the surroundings. The cycle is closed by the pump which generates the maximum pressure of the Rankine cycle before the working fluid enters the vaporiser again.

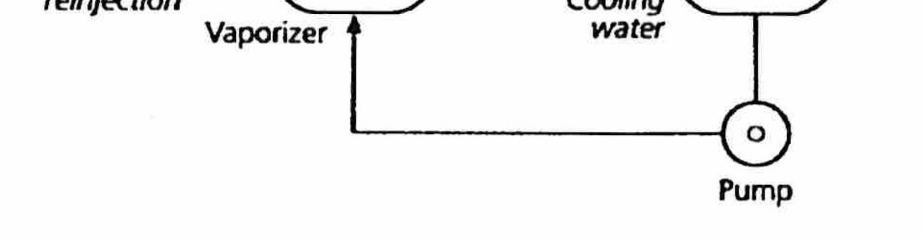

Figure 4 Sketch of a binary fluid cycle power plant (Rankine cycle). Geothermal hot fluid is used for adding heat to the power cycle fluid before power extraction in the turbine. The power working fluid is condensed at low pressure in the condenser before it is pumped up to high pressure and the cycle is closed.

The geothermal fluid can be recirculated back to the geothermal reservoir after the heat exchange process. Different geothermal reservoirs require different techniques and for geothermal heat from aquifers the fluid in the aquifer can be used as geothermal fluid for heat exchange with the power cycle working fluid. Often the pressure in the aquifer exceeds the hydrostatic pressure, and no pumping power is required to get the geothermal fluid at the power plant site. The geothermal fluid can be fed back to the same reservoir or it can be rejected in a shallower aquifer or to the sea surface which require less pumping work, and the net output from the power plant increases. This concept with use of geothermal fluid from aquifers is beyond scope of this study, but it will be a very interesting concept for further studies for North Sea conditions. Geothermal systems using fluids from aquifers directly often require a separation process to remove impurities and inert gases before entering the heat exchangers. The geothermal fluid in the Electricity by Liquid Injection (ELI) concept uses a closed pipeline for the "geothermal fluid", and in this case a separation process of the geothermal fluid is avoided. In the ELI concept the geothermal heat will be recovered by a heat exchange between the geothermal heat resources and the fluid inside the pipeline down in the wells. The closed pipeline for recovery of geothermal heat exploits abandoned oil/gas wells, and the principle requires connections between two or more wells to enclose the pipelines. In principle the heat recovery part of the pipeline can be located in both hot rocks and aquifers.

In Figure 4 a simple pressure binary fluid cycle is shown, but there are several possibilities to increase both the efficiency and the exergy efficiency in the Rankine cycle. An introduction of one more pressure level of the power cycle working fluid in the heat exchange with the geothermal fluid increases the efficiencies by better adjusted temperature profiles of the two fluids. This dual pressure cycle splits the working fluid into two pressure levels before vaporising and superheating. The expansion takes place in a common turbine where the flow with lower pressure is fed into the turbine at a lower pressure level. The system uses one common condenser. The temperature profile of a dual pressure power cycle is shown in Figure 5. The dual pressure power cycle leads to lower return temperature of the geothermal fluid and more heat is extracted pr. unit flow rate compared to the single pressure power cycle.

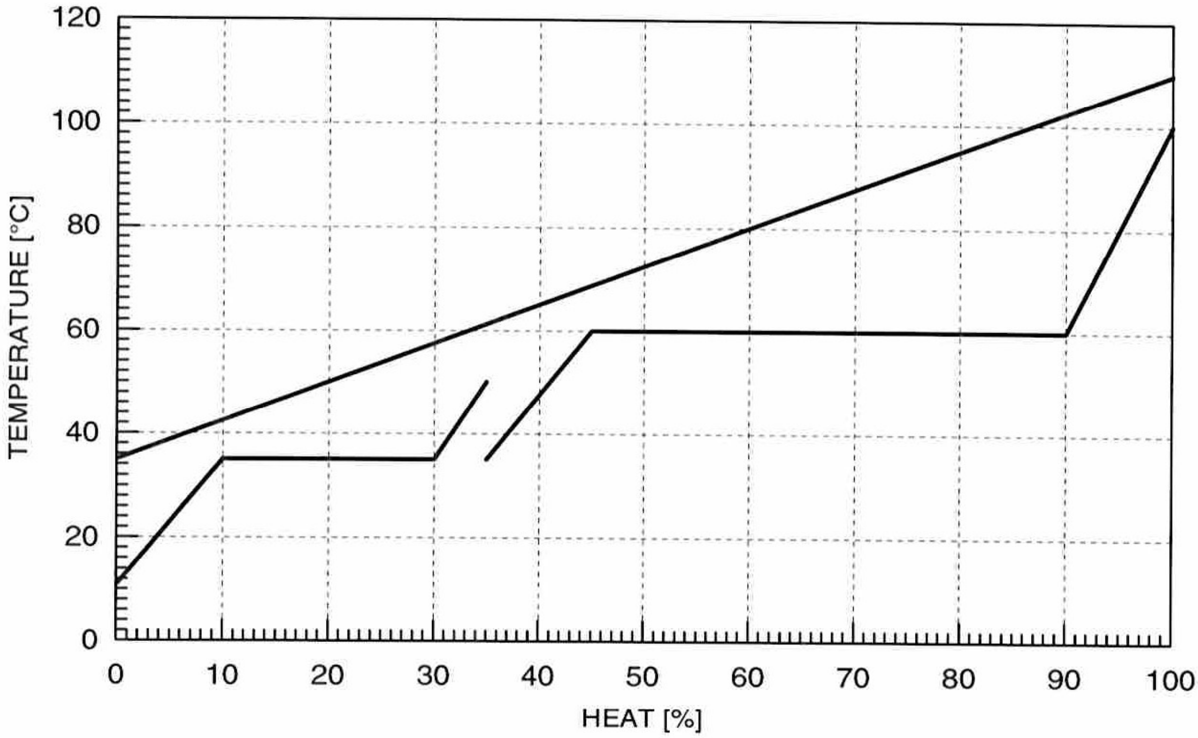

Figure 5 Temperature profile of a binary fluid geothermal power plant based on a dual pressure power cycle

Topping / bottoming cycles are binary fluid power cycles with two separated "power cycles". This type of power plant often uses two different working fluid types, and the two cycles are connected by a heat exchanger between the high temperature cycle condenser serving the low temperature cycle vaporiser with heat. The investment costs of this type of plant are relatively high, and it is not further considered in this work.

The theoretical advantages of binary fluid cycles compared to direct-use cycles are:

I. It enables more heat to be extracted from the geothermal fluids by rejecting them at lower temperature

II. It makes low temperature geothermal fluids more economical than direct-use cycles

III. It makes use of low temperature geothermal sources possible for power generation where direct-use cycles are not available

IV. The use of working fluids with low boiling point enables compact turbines and avoids occurrences of sub-atmospheric pressures at any point in the working cycle
V. It confines chemical problems to the heat exchanger alone
VI. It enables use of hostile and toxic fluids as geothermal resources
VII. It enables use of geothermal fluid with high portion of inert gases
VIII. It enables water/steam mixtures without separation

The theoretical disadvantages of binary fluid cycles compared to direct-use cycles are:

I. It requires use of heat exchangers which is wasteful in temperature drop, are costly and fouls with dirty fluids
II. It requires a feed pump in the working cycle which consume energy and investment capital
III. Some working fluids are toxic, flammable and environmentally harmful
IV. It requires large amount of cooling water and a pump in the cooling circut which consumes energy

3.3.1 Power cycle working fluid

Water as working fluid in power cycles has been used widely for very long time, and the characteristics of water as working fluid are good. Hydrocarbons, fluorocarbons, and other organic working fluids have been examined for potential use in low-temperature power cycles as a replacement of water. Up to now refrigerants based on chlorine fluorine carbon (CFC) compositions have been very popular in heat pumps and refrigeration systems. The impact on the ozone layer and the greenhouse effect has lead to a stagnation or almost complete stop for using this type of working fluids in new applications. Hydrocarbons, water and ammonia are the interesting working fluids for low temperature geothermal binary fluid cycles in the absence of CFC working fluids. The use of water/steam requires very large turbines compared to an ammonia turbine with similar ambient conditions.

The major disadvantage of hydrocarbons is their flammability, which requires costly explosion-proof equipment and ventilation systems. Hydrocarbons like propane, pentane and isobutane are widely used in refrigeration cycles, and specially isobutane shows good qualities for use in binary fluid cycles for geothermal power plants (Milora and Tester, 1976). At geothermal temperatures below 160 °C ammonia shows better exergy efficiency than isobutane, but at temperatures above this isobutane shows slightly better characteristic than ammonia (Milora and Tester, 1976).

Ammonia is a very interesting working fluid in refrigerating cycles and binary fluid geothermal power plants. The restrictions on the use of CFC fluids have lead to a new renaissance for ammonia, and the properties of ammonia are very good for use in binary fluid cycles in geothermal applications.

At temperatures below 300 °C the rate of dissociation of nitrogen and hydrogen in ammonia is relatively slow, and the performance in power cycles is good (Edwards, 1982). Laboratory tests carried out at SINTEF (Pettersen, 1992) have shown that decomposition of ammonia in power cycles below 400 °C is not a significant problem.

An overall analysis (Hornnes and Bolland, 1991) concludes that for Rankine cycle applications water and ammonia are the preferable working fluids, and at high source temperature (>350 °C) water has no alternatives. The mixture of water and ammonia (Kalina cycle) is a very interesting choice for good performance power cycles, but the process is so far very complex and expensive. From this point of view the Kalina cycle is not an actual cycle to be installed on an offshore platform.

The working fluid preferred in this study is ammonia due to good thermodynamical properties and relatively small units of the power cycle turbines. The low flammability compared to that of hydrocarbons is also preferable for offshore purposes.

3.3.2 Direct heat exchange system

Most binary fluid power cycles use conventional heat exchangers and this requires a separation of the working cycle fluid and the geothermal fluid. Heat transfer in a heat exchanger requires a temperature difference between the two fluids and this leads to losses in the power cycle, and reduced efficiencies and exergy efficiency in the power cycle. An increase in the efficiency can be obtained by a direct heat exchange system with direct contact of the power cycle working fluid and the geothermal fluid. This system requires two fluids with very low solubility to prevent a mix of the to fluids. The heat transfer in such a system is very effective. This concept has not got a breakthrough in geothermal power plant systems and will not be considered further in this study.

3.4 Case study

The efficiency and the exergy efficiency of binary fluid working cycles are very sensitive to the temperature of the geothermal fluid. High temperature levels leads to a relatively high performance factors, and the sensitivity of different parameters is examined in this work. The base case in this work is a single pressure binary fluid cycle with a net power output of 5 MW with an ammonia working cycle as fluid and water as geothermal fluid. In Figure 6 different parameters for a single pressure working cycle is shown as function of geothermal fluid temperature. The parameters are calculated only for the power cycle itself, and auxiliary power required for condensers and geothermal fluids are not included. This investigation is performed only to describe the sensitivity of the geothermal fluid temperature to the power cycle itself. The single pressure cycle with a geothermal fluid temperature of 110 °C is used to compare the relative changes in parameters as efficiency, exergy efficiency, amount of heat recovered from geothermal fluid (geothermal heat), mass flow of NH_3 (ammonia) and geothermal fluid flow. An increase in geothermal temperature from 110 °C to 190 °C increases the exergy efficiency of a factor of 1.22 and the efficiency at a factor of 1.95. The efficiency and exergy efficiency at 110 °C are 6.6 % and 45 % respectively. The other three parameters plotted are geothermal heat, mass flow of NH_3 and geothermal fluid flow. These factors are reduced as the temperature of the geothermal fluid increases, and the required sizes for pumps, heat exchangers and auxiliary power are reduced.

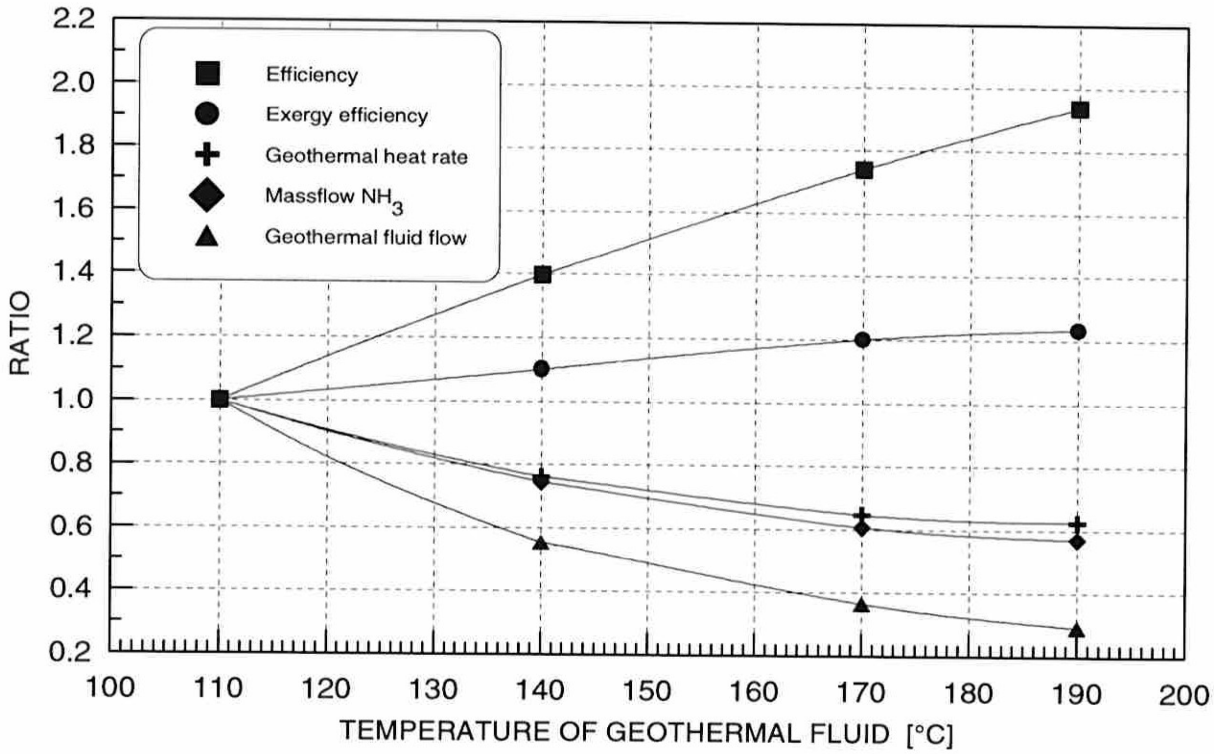

Figure 6 Ratios of different values for a single pressure binary fluid cycle as function of temperature of geothermal fluid. The ratios are calculated from base case with geothermal fluid temperature of 110 °C. The efficiency and the exergy efficiency of base case are 6.6 % and 45 % respectively. Auxiliary power for geothermal fluid and condenser are not included.

The utilization of the heat in the geothermal fluid in the power plant is restricted by the pinch point in the heat exchange between the geothermal fluid and the power cycle working fluid. The pinch point is the point of the temperature profile with smallest temperature differences as shown in Figure 5. Single pressure power cycles with relatively high pressure level have pinch point at high temperatures because pinch point temperature is related to the pressure of the working fluid in the vaporiser in the power cycle. In Figure 7 efficiency, exergy efficiency, amount of heat recovered from geothermal fluid (geothermal heat), mass flow of NH_3 (ammonia) and geothermal fluid mass flow are plotted as ratios of the base case single pressure cycle. The base case single pressure cycle is referred to the cycle with highest pressure without expansion into the two phase fluid flow region in the exit of the turbine. The results plotted in Figure 7 show best efficiency and exergy efficiency for the base case single pressure cycle. Cycles reducing the return temperature of the geothermal fluid (lower pressure level in the vaporiser of the working fluid) show less efficiency and exergy efficiency. The required amount of mass flow of geothermal fluid and power cycle working fluid (NH_3) increase with lower return temperature of the geothermal fluid, and this leads to increased size of the heat exchangers which is not recommended. The increase in fluid flow of both geothermal fluid and cycle working fluid is related to the reduced efficiency of the power cycle when reducing the pressure level in the power cycle.

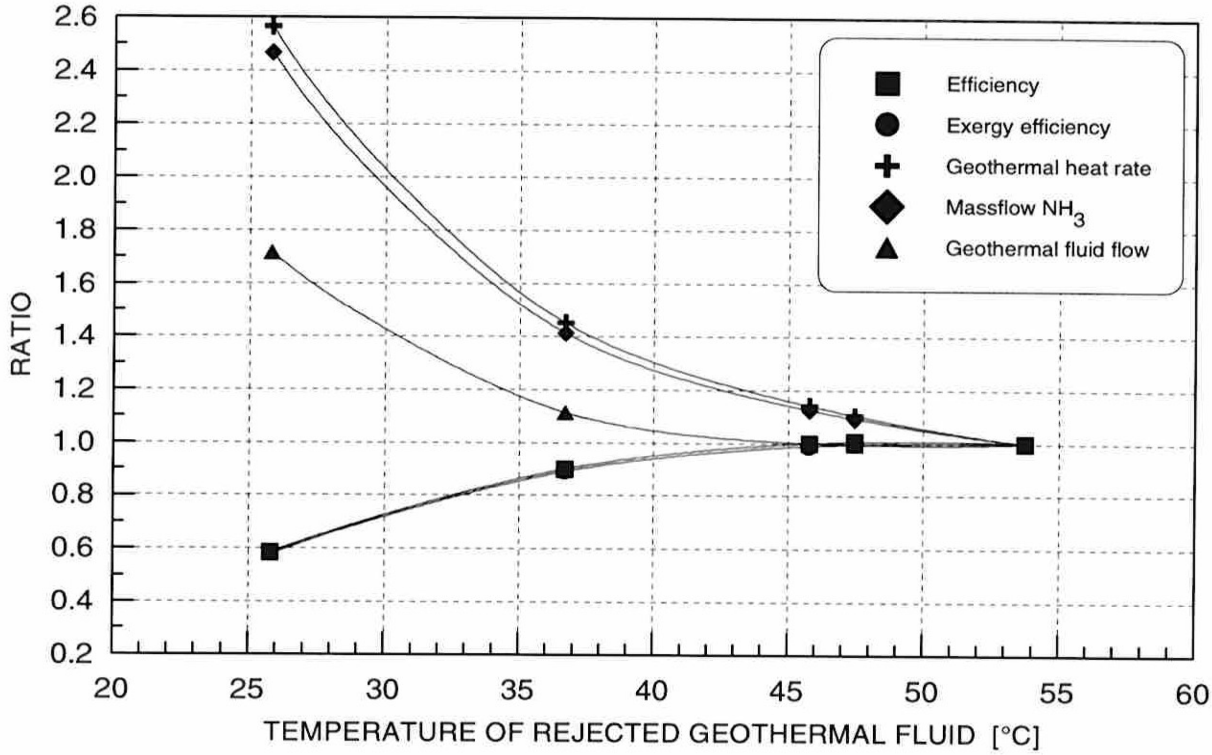

Figure 7 Ratios of different values for a single pressure binary fluid cycle as function of RETURN temperature of the geothermal fluid. The ratios are calculated from base case which obtain return temperature of the geothermal fluid at 54 °C. The efficiency and the exergy efficiency of base case are 6.6 % and 45 % respectively. Auxiliary power for geothermal fluid and condenser are not included. In the figure the efficiency and the exergy efficiency ratios are overlapped.

In the further study an investigation of different binary fluid cycle concepts are evaluated to show the characteristics of the different solutions. Four different cycle concepts are evaluated and these concepts are single pressure cycle, reheat cycle, dual pressure cycle and dual pressure cycle with reheat. All the concepts are evaluated for geothermal fluid temperature of 110 °C. The definition of efficiency considered in this study will determine the best cycle due to power generation of a given geothermal heat source.

SINGLE PRESSURE CYCLE

This is the base case single pressure cycle, and the cycle is described under chapter 3.3 Binary fluid cycles at page 13 earlier in this report. A simple sketch of the single pressure cycle is shown in Figure 4. This is the basis cycle, and a comparison of the different power cycles is worked out and described later in the report.

REHEAT CYCLE

This cycle operates at a higher pressure of the working fluid in the power cycle, and the working fluid is reheated at an intermediate pressure before expansion in the lower pressure part of the turbine. The reheat cycle is shown in Figure 8. This cycle gets a low cycle efficiency, and a relatively low exergy efficiency, because the cooling of the geothermal fluid is lower compared to the other cycles.

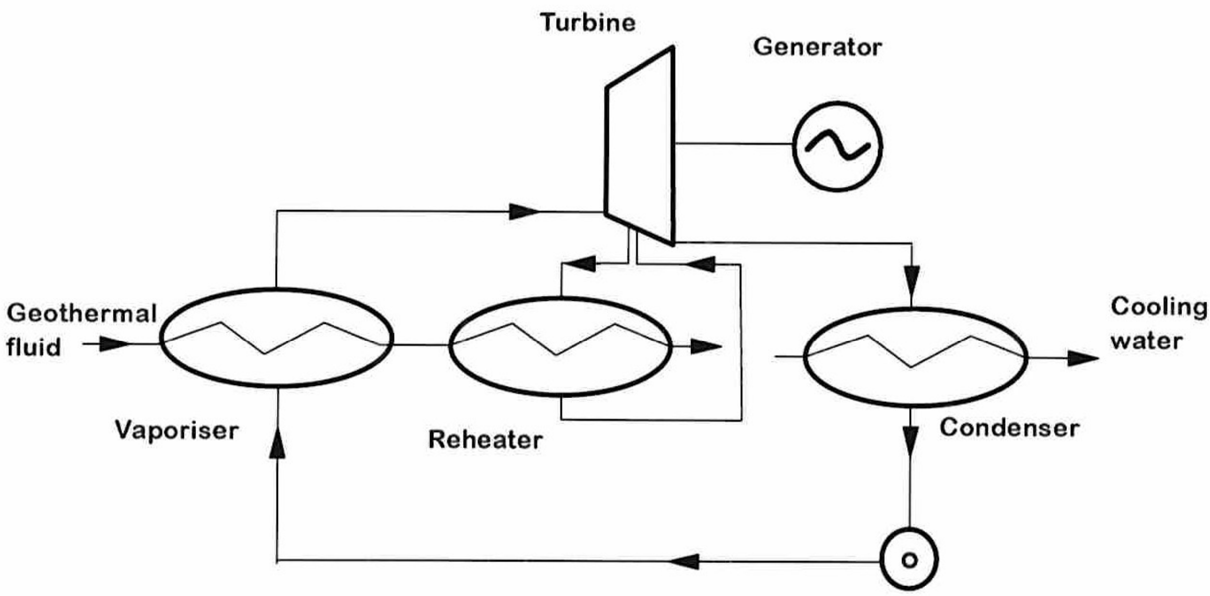

Figure 8 Binary fluid power cycle with reheat for geothermal power production

DUAL PRESSURE CYCLE

Dual pressure binary fluid cycles have two pressure levels of the vaporising and superheating process, and this lead to a better utilization of the heat in the geothermal fluid. The temperature profiles in the heat exchange between geothermal fluid and the power cycle working fluid is better adjusted and the temperature of the geothermal fluid is relatively low before returning to the well again. The temperature profiles for the dual pressure cycle are shown in Figure 5.

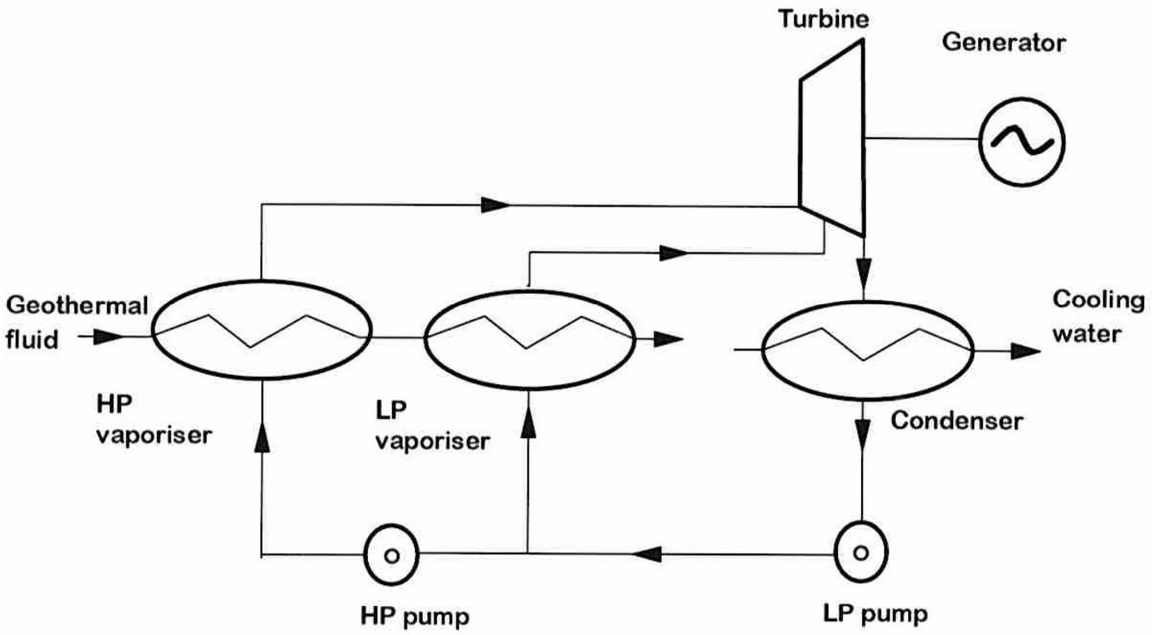

Figure 9 Dual pressure binary fluid power cycle

DUAL PRESSURE CYCLE WITH REHEAT

This cycle is a combination of the reheat cycle and the dual pressure cycle. The temperature of the rejected geothermal fluid is relatively high, and this leads to high working fluid mass flow in the power cycle. Again this lead to a relatively high amount of heat to be rejected in the condenser.

From Figure 10 it can be stated that high efficiency of the power cycle leads to relatively low geothermal fluid flow. This means that the heat in the geothermal fluid is more effectively utilised than cycles with less efficiency. On the other side it can be stated that the power cycles with relatively low efficiency due to low utilization of the geothermal heat have less fluid flow in the condenser (at constant geothermal heat source temperature), and thereby less heat to be rejected to the surroundings. This is a result of the relatively high quality (exergy) of the heat from the geothermal fluid at the high temperature levels. This leads to relatively small condenser and pump in the cooling water circuit with low efficiency (at constant geothermal heat source temperature). In this investigation it is very important to state that the geothermal source temperature has been constant. The total auxiliary power for driving the cooling water and the geothermal fluid have to be considered to find the optimal power cycle concept. From this point of view further investigations for determining the best power cycle have to be carried through, and the auxiliary power for driving the geothermal fluid and the cooling water have to be considered. In the further investigations the reheat cycle and the dual pressure cycle are considered, because these two cycles show the extreme points in these analyses.

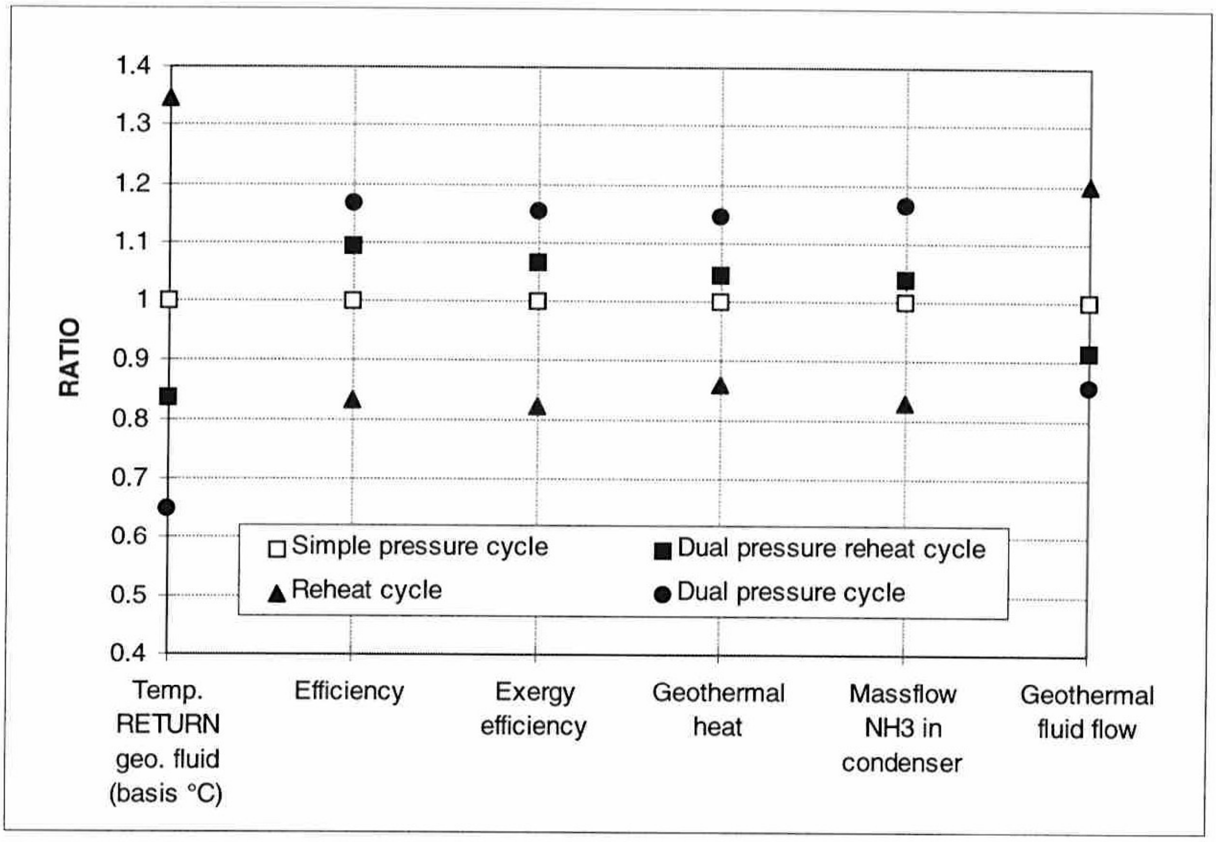

Figure 10 Comparison of different binary fluid cycle concepts for geothermal power production based on the single pressure cycle. Auxiliary power for driving geothermal fluid and cooling water are not included. The efficiency and exergy efficiency for the simple pressure cycle are 6.6 % and 44 % respectively, and the return temperature of the geothermal fluid is 54 °C.

3.4.1 Condenser

The power required for driving the cooling water to the condenser is determined by the total volume of cooling water and required pressure level at the outlet of the cooling water pump. Geothermal power plants for use on abandoned platforms have to be placed on the platform deck, and the difference in altitude from sea level to the condenser of the power plant affects the total pressure required at the outlet of the cooling water pump. The altitude from sea level to the condenser alternates from platform to platform and number of floors. From this point of view it may be favourable to sink the condenser closer to sea level or down in the sea. This requires special installations and/or types of condensers. This will also affect the length of the pipelines in the power cycle and the pressure drop will increase. The optimal of this solution have to be considered carefully and optimised by alternating the temperature rise of the cooling water. The cooling water mass flow will affect the temperature difference of the cooling water in the condenser. The change in water flow rate will affect the power for driving the cooling water in the condenser circuit, and the lower pressure level in the power cycle to obtain required temperature differences in the condenser. In this study a comparison of the dual pressure binary fluid cycle and the reheat binary fluid cycle is considered. In the calculations the altitude from sea level to the condenser is assumed 35 metres, and the total pressure increase in the cooling water pump is calculated to 4 bar. This includes the friction pressure drop and the static pressure difference. In Figure 11 the ratio of efficiency and exergy efficiency of the dual pressure cycle are plotted as function of temperature increase of the cooling water in the condenser. Without auxiliary power for cooling water pump and geothermal fluid the efficiency and exergy efficiency of the dual pressure cycle is 7.7 % and 52 % respectively. The optimal temperature increase (difference) of the cooling water is 6 °C, and the efficiency and the exergy efficiency of the power production have a ratio of 0.7 compared to the dual pressure cycle without auxiliary power. This means that the power for the cooling water pump under these conditions requires 30 % of the power produced in the turbines for the dual pressure cycle.

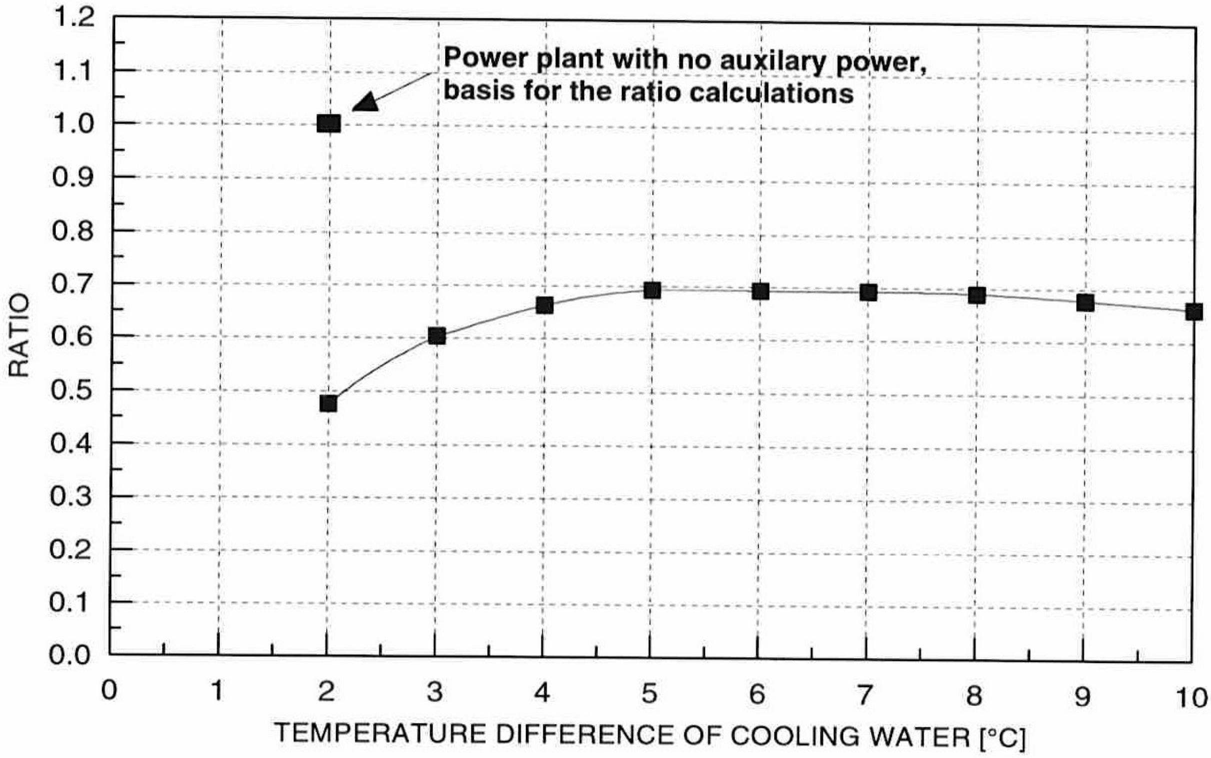

Figure 11 Influence of efficiency and exergy efficiency due to power demand for cooling water operation for a <u>DUAL PRESSURE CYCLE</u> with altitude from sea level to the condenser of 35 meters as function of cooling water temperature difference. Basis for the ratio is a dual pressure cycle with no auxiliary power for geothermal fluid and cooling water operation

In Figure 12 the ratio of efficiency and exergy efficiency of the reheat cycle are plotted as function of temperature increase of the cooling water in the condenser. The efficiency and exergy efficiency of the reheat cycle are 5.5 % and 37 % respectively without auxiliary power for cooling water and geothermal fluid pumping. The optimal temperature difference of the cooling water is 6 °C, and the efficiency and the exergy efficiency of the power production have a ratio of 0.8 compared to the reheat cycle without auxiliary power. This means that the power for the cooling water pump under these conditions requires 20 % of the power produced in the turbines in the reheat cycle. From this point of view it can be stated that the reheat power plant will be preferable compared to the dual pressure cycle due to less power demand for cooling water.

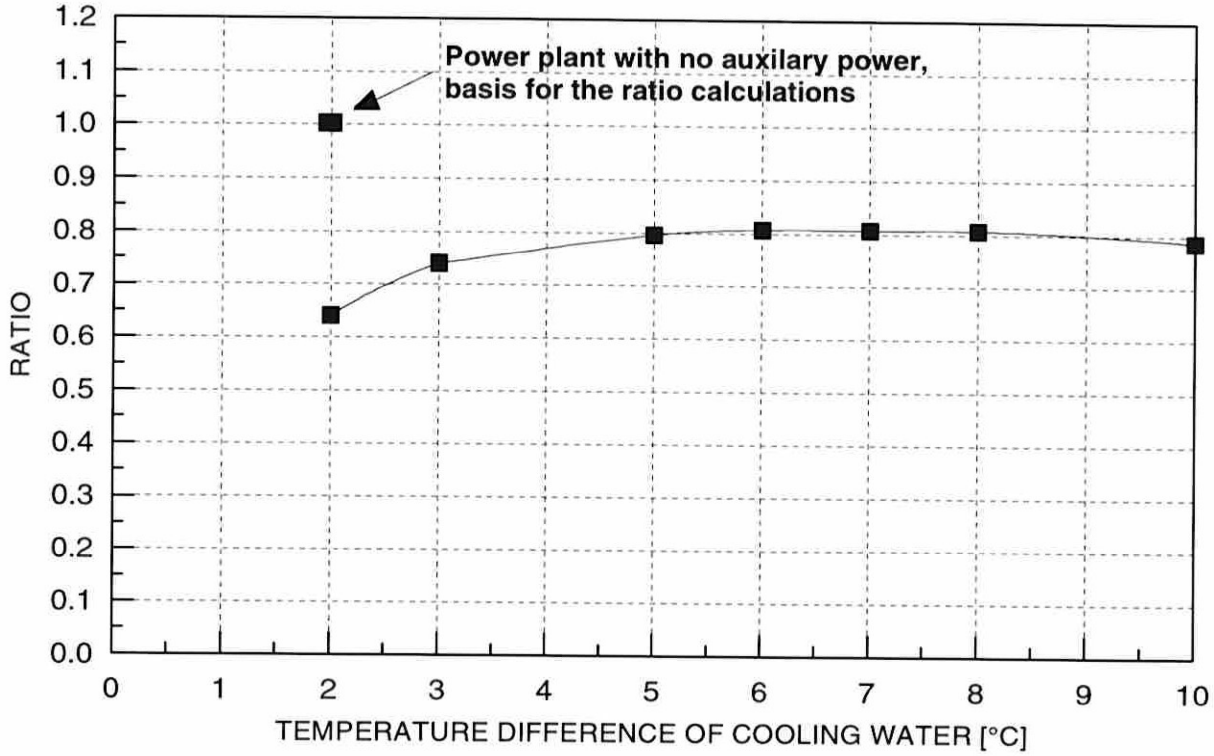

Figure 12 Influence of efficiency and exergy efficiency due to power demand for cooling water operation for a <u>REHEAT CYCLE</u> with altitude from sea level to the condenser of 35 meters as function of cooling water temperature difference. Basis for the ratio is a reheat cycle with no auxiliary power for geothermal fluid and cooling water operation

From these analyses it is obvious that other solutions for the condenser will increase the efficiency of the power plant. If it is possible to build the condenser at sea level or under sea level the reduction of the efficiency and exergy efficiency will be lowered considerably even though the pressure losses in working cycle increase. This kind of solutions requires some fixing device units, and there are great challenges for finding the best solutions. A condenser in the sea level will reduce the efficiency and the exergy efficiency approximately of 9 % and 5 % for the dual pressure and the reheat cycle respectively due to power demand for cooling water pump compared to the power output of the plant with no auxiliary power. The conclusion is that it is very important how to arrange the condenser in such a power plant located at platforms, and to look for solutions of the power plant close to sea water level for the future.

3.4.2 Geothermal fluid

A comparison of the dual pressure cycle and the reheat cycle can not be performed without also taking into account the power for driving geothermal fluid in the wells for geothermal heat recovery. Up to now it is stated that the reheat cycle requires a higher mass flow of geothermal fluid compared to the dual pressure power cycle. A careful investigation of possible mass flows pr. well and power required, has to be conducted to select the best power plant cycle concept. A reheat cycle will probably require greater diameters of the geothermal fluid pipeline or more wells. The power for driving the geothermal fluid is essential and the choice of power cycle concept will also be highly dependent on investment costs in the wells. The reheat cycle requires approximately 35 % more geothermal fluid at 110 °C with a condenser at sea level compared to a dual pressure cycle. Careful estimates are required for a detailed calculation of pipeline length and number of wells required for the geothermal fluid. A heat transfer and pumping work ratio has to be determined for different locations of the pipeline for geothermal heat recovery. The pipeline with the geothermal fluid will also lose some heat in the transportation from power plant and up/down into the wells. An insulation of the geothermal pipeline in the transportation section is probably required. An estimation of the power for driving the geothermal fluid is a very difficult task and has not been performed in the preliminary study of the well conditions.

3.4.3 Total performance data

The total performance data for the geothermal power plant are directly affected by the specific installation site and geothermal heat source temperature. The analysis performed in this study gives a relative potential for different binary fluid cycles, and power plants designs. From these analyses a geothermal power plant with a geothermal fluid of 110 °C should get an efficiency at maximum 7.5 % depending on power demand for geothermal fluid and cooling water. A geothermal fluid temperature of 190 °C gives an efficiency at maximum 12 % depending on the power for driving the geothermal fluid and cooling water.

The total performance data for an Ormat application has efficiency and exergy efficiency of 4 % and 24 % respectively given from a required amount of water of 1100 tons pr. hour at 110 °C and a power production of 5 MW (Ormat 1995). Ormat is a manufacturer of power cycles for utilisation of low temperature heat resources. These are indicative numbers, and the Ormat cycle is not very well documented. Ormat produces only site specific and specialised power plants, and detailed boundary conditions are required to get accurate data for performance and economical data.

3.4.4 Weight

The total weight of a geothermal power plant has to be considered for offshore installations. Up to now most of the equipment for geothermal power production are designed for onshore applications, and the aspects of weight and space have been of relatively low importance. A potential for lowering the weight of a power plant is related to the heat exchangers, and most applications use shell and tube heat exchanger which are heavy and space intensive compared to compact plate fin heat exchangers. In this study an intensive inquiry has been performed, and most heat exchanger manufactures have too small units for compact heat exchangers for the power plant investigated in this study. One manufacturer has promised a full design of the heat exchangers, but it has not arrived yet. Normally the potential for weight reduction of a conventional plant based on shell and tube heat exchangers by introducing compact plate fin heat exchangers is considerable. The ratio of volume for shell and tube heat exchangers compared to plate and fin heat exchangers are approximately 20 (Sumitomo, 1995).

An overall calculation from Ormat (1995) for a 5 MW power plant gives a total weight of approximately 150 tons. The power plant is divided into modules with a total of 5 to 6 ISO 40 feet containers. A potential of lowering these weight is espesially related to the heat exchangers.

The weight of the turbines and the generator for a power production of 5 MW is approximately 37 tons.

3.4.5 Economics

An investigation to find the economical aspects of a binary fluid cycle geothermal power plant is very complex because the parameters for each plant are site specific, and the conditions on an offshore platform require special demands. The specific capital cost to build a geothermal power plant exclusive the well cost varies widely depending on the type of technology used, and DiPippo (1991) indicates that the investment costs are in the range of \$ 1000 - 3000 pr. $kW_{electric}$ for a binary fluid cycle.

In Figure 13 a breakdown of the investment cost for a binary fluid cycle is shown and the relative cost of the heat exchanger and the condenser are high compared to the rest of the power plant without cost for the wells. The investment costs of the heat exchangers are important to determine for a realistic calculation of the total investment cost. New technology of compact heat exchangers based on the plate fin concept are improving and new applications are developed. This type of heat exchangers can steadiness sustain higher pressures, and the use of this type of heat exchangers increases. The weight of this type of heat exchanger is low compared to the traditional shell and tube heat exchanger and therefore preferable for use on offshore platforms. However these compact heat exchangers often are designed for applications with lower capacity than required for the geothermal power plant in this study. This gives many components in parallel, and the distribution of the fluid can lead to some problems. Secondly many small units require a lot for piping and valves and the investment costs increase rapidly. An investigation among a lot of the world biggest heat exchanger manufactures verify these problems, and it has been difficult to get useful data for the heat exchangers. Some data are expected, but at the moment SINTEF Thermal Energy and Hydropower have not received the information.

The complete cost for the turbine and generator are in the order of 290 \$/$kW_{electric}$ for the size required in this study.

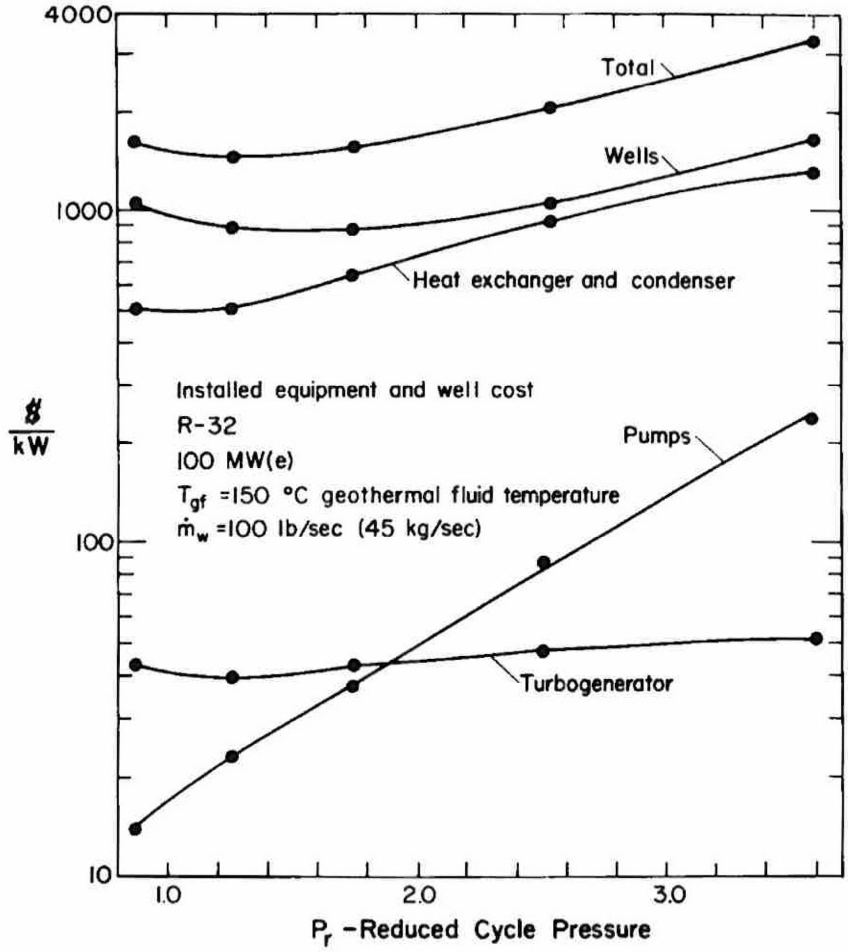

Figure 13 Equipment and well cost break-down for a R-32 binary fluid cycle with a 150 °C liquid-dominated resource and rejection to a sink at 17 °C. Costs (1976$) are a function of reduced cycle pressure (After Milora and Tester, 1976).

The installed costs of a binary fluid cycle plant are also related to the efficiency of the plant. Low geothermal fluid temperature leads to low efficiency and relatively larger components for the heat exchanger and condenser specially, but the size of turbine and pump is also increasing. In Figure 14 the relation of geothermal fluid temperature to investment cost of a binary fluid power cycle is shown. The temperatures of both the geothermal fluid and the condensing temperature are of great importance.

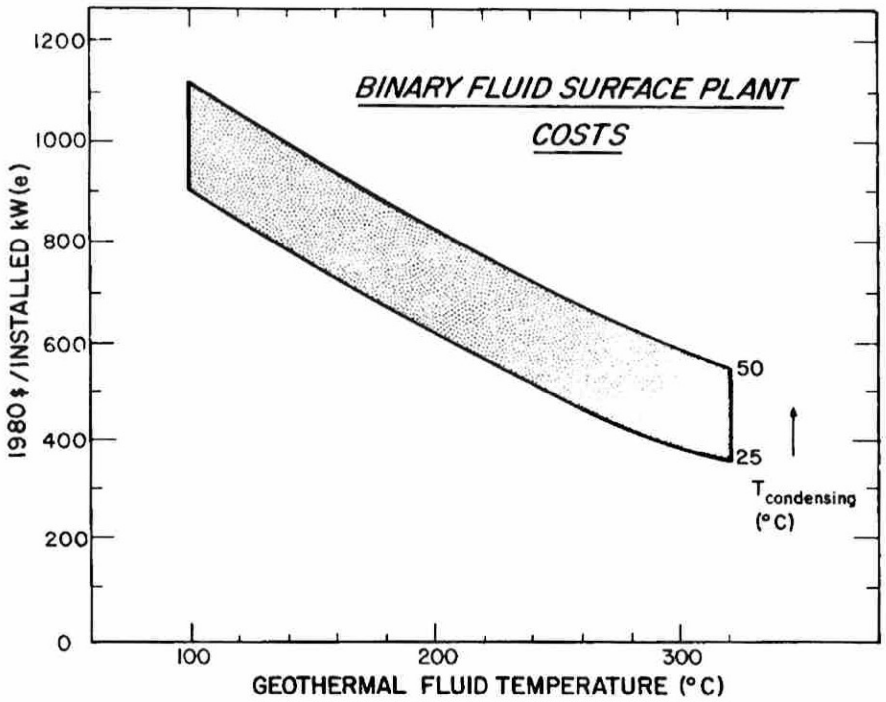

Figure 14 Estimated binary fluid plant cost in 1980$ as function of geothermal fluid temperature and condensing temperatures (After Edwards et. al, 1982).

In this study the geothermal fluid temperature is assumed 110 °C. The investment cost of a binary fluid power plant on a platform location offshore is assumed to be 3500 $\$/kW_{electric}$ in this study. The interest rate and economical lifetime are 7 % and 25 years respectively. The cost is relatively high because of the low temperature of the geothermal fluid, and the location on offshore platform requires special equipment and security installations. If the geothermal fluid temperature is increased the investment cost will be reduced and the power plant will get lower production cost. The costs of removing the abandoned platforms and the costs of installations in the wells have to be taken into account for determining the total economical aspects of the power plant considered in this study. The costs of removing platforms are out of scope for this study.

The fixed operational costs of the power plant are due to personnel and insurance required for the operation of the plant.

The total production cost of the binary fluid power plant is estimated to 7-8 Cent/kWh. See Figure 15. This production cost refer to 7500 hours operational time per year. The cost are related to the power plant only, and that the required amount geothermal fluid is available at the surface.

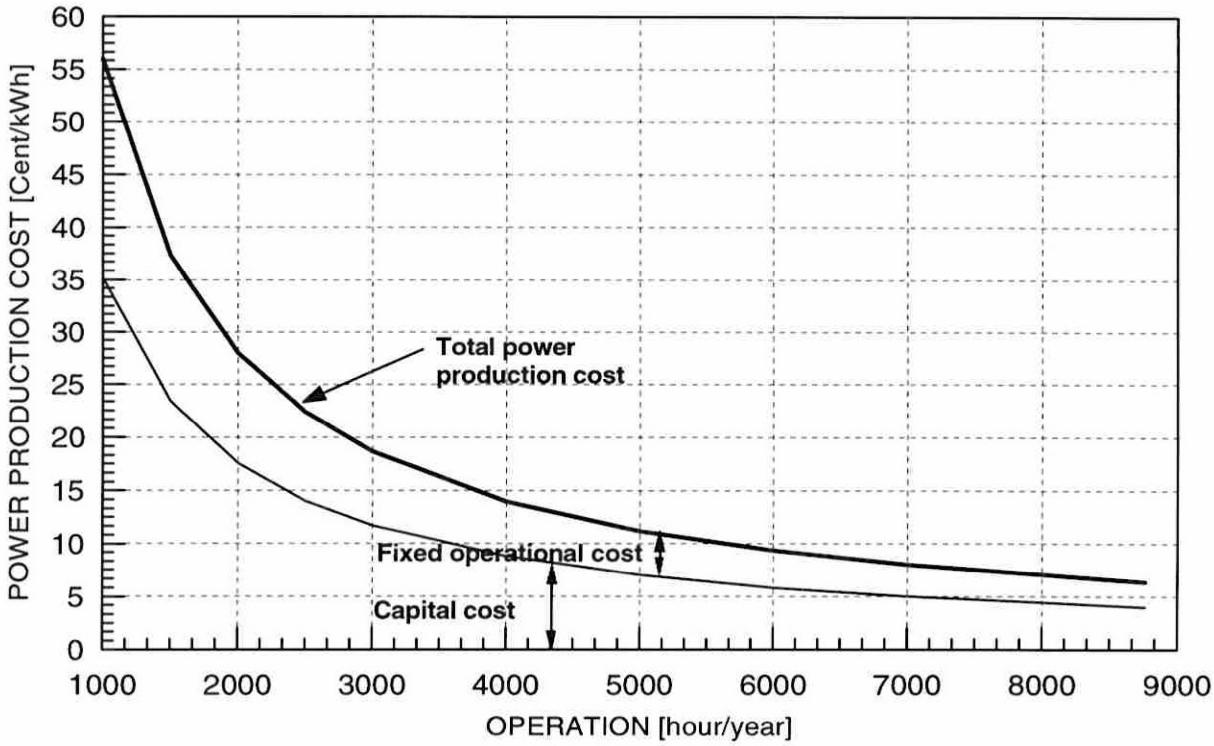

Figure 15 Production cost for a binary fluid cycle power plant with geothermal fluid temperature of 110 °C. The cost of the wells and the benefit of further use of abandoned platforms are not taken into account.

A potential for reducing the investment cost of the power plant is highly related to the heat exchangers by introducing compact plate fin heat exchangers. Geothermal resources onshore will also reduce installation cost due to lower demand for safety and operational procedures. At least the temperature level of the geothermal source is of great importance in reducing the investment cost for the power plant. With a geothermal heat source of 250 °C compared to a geothermal heat source of 110 °C the investment cost of the power plant can be reduced approximately 30 %.

4 CONCLUSION

The binary fluid power plant analysed in this report utilise geothermal fluid of a temperature of 110 °C. The analysis carried through is based on the ELI concept with a closed pipeline for the "geothermal fluid". The total efficiency of the power plant with a condenser at sea level is maximum 7.5 % depending on the power for driving the geothermal fluid. Higher geothermal temperatures will give better efficiencies. A geothermal fluid temperature of 190 °C gives an efficiency in the range of maximum 12 % depending on the power for driving the geothermal fluid and cooling water.

The total production cost of the binary fluid power plant is estimated to 7-8 Cent/kWh. This production cost refers to 7500 hours operational time per year, and the costs are related to the power plant only.

The potentials for lowering the production cost of the binary fluid power plant are mainly related to the geothermal fluid temperature and by introducing compact heat exchangers in the power cycle.

The potentials for lowering the weight of the binary fluid power plant are mainly related to the heat exchangers in the power cycle.

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Part III

CONCLUSIONS AND RECOMMENDATIONS

Table of Contents

1. Heat extraction potential

We have presented a model for the heat transfer process in the primary loop of a geothermal installation using the ELI concept. The heat transfer in the body of the formation has been assumed to be dominated by heat conduction. Both radiation and body-convection have been neglected compared to the conduction mechanism as discussed in Section 2 of Part I. We have then analytically solved the model for the temperature field and the geothermal heat that can be extracted from the formation. In this way we were able to obtain an upper bound estimate for the heat power. We found the upper bound for the geothermal power to be strongly limited by the actual value of (a) the temperature difference between the rock and the injection fluid, and (b) the effective thermal resistance of the formation which grows (logarithmically) with time and is inversely proportional to the low thermal conductivity of the rock. After 5 years of service the maximum thermal power that can be extracted from a typical North Sea well is in the range of 175-200kW$_t$ per kilometer along the well. This result follows from considering (i) the initial temperature of the rock 50°C hotter than the fluid at the inlet point, (ii) a well diameter in the range 10"-15", and (iii) neglecting the convective thermal resistance as well as the conductive thermal resistance of the casing and cementing of the well. The additional consideration of the thermal resistances would limit even more the heat power that can be produced. Also, within the assumptions made it has not been relevant to consider the pumping power required for circulating the injection fluid. A more accurate analysis would have to include the pumping power, as explained in Section 2 of Part 1. Even though some of the pumping power would be recovered as friction generated heat in the loop, the net thermal power produced will be lower than in the frictionless case. Because of the relatively low heat transfer from the formation, a long loop would be required in order to heat the injection fluid sufficiently. The necessary pumping power would therefore be relatively large compared to the heat power extracted, and would affect the net thermal power considerably. The figures above must therefore be considered as representing a *best case* value valid for the most favorable conditions.

2. Heat conversion efficiency

For the analysis of the binary fluid power plant we have assumed that the temperature of the injection fluid at the outlet of the primary loop is 110 °C. The total efficiency of the power plant with a condenser at the sea level is at most 7.5 %, its exact value depending on the power required to pump the injection fluid. The efficiency improves considerably for higher temperatures of the injection fluid: When the temperature at the outlet of the primary loop is 190 °C the efficiency for conversion is at most 12 %.

3. Economics

The estimated minimum cost level in a geothermal electric power plant based on the ELI-concept shows a large variation. The ELI- concept is based on utilization of an existing offshore installation in the North Sea. Based on the upper bound estimates for the geothermal heat power and the estimated cost range and efficiency of the thermal electric conversion process for a geothermal plant offshore, we have calculated the minimum cost per kWh for a 5 MW_e power plant with 7.5% efficiency and 35 loops. The resulting cost range is 4-14 NOK/kWh.

In order to produce more precise cost estimates for the geothermal power plant a case study of an actual candidate installation is required. The study presented here is mainly performed to get an overall feeling of the cost picture for a general offshore installation. We have estimated *expected* costs based on direct input from the industry, considering also the actual investment level and the state of the art of the technology involved.

We conclude that the ELI concept might only be found economically attractive in the North Sea provided that drilling costs can be reduced by, at least, a factor of 10 compared to present cost level.

We have not given priority to a more detailed technical and economical evaluation of the cost components due to the resulting high cost estimates. The relatively low heat extraction and production potentials and the high cost level in the North Sea, results in a high cost for the produced electrical power. Economically attractive electric power production using the ELI-concept in the North Sea demands significant improvements in the cost efficiency, especially for the drilling and completion of the looped wells.

New technology for drilling and completion of wells may reduce the costs dramatically. This will, however, also reduce the economical benefit of using *existing* wells in the North Sea.

We have neither taken into account the design lifetime of platform installations. Whenever possible, extending this lifetime will imply additional costs which have not been taken into account in this report.

4. Recommendations for improvements and application of the ELI concept

To improve the geothermal heat power one might consider drilling deeper wells to have access to higher temperatures. Alternatively one might also consider drilling several "connection" wells at the economically accessible depths multiplying in this way the power extracted by the number of wells. Finally, increasing the diameter of the geothermal well would also produce a slight increase of the heat power. All these alternatives have the penalty of adding cost to the geothermal installation. Technological improvements should concentrate on reducing drilling costs. Also the heat exchanger units in the binary fluid power cycle should be further investigated to reduce the total weights of the plant and the investment costs. Combined with application in areas with higher geothermal gradients or with naturally occurring convection cells in aquifers, this could make the ELI concept economically attractive.

Appendix A: Description of the ELI concept

Del 1

Stavanger, 30 mai 1995

Enkel og forståelig beskrivelse av produktideen.

Oppfinnelsen angår en metode for å skape ny og miljøvennlig fornybar elektrisk energi ved bruk av en veskebåret geotermisk lavtemperatur lukket energikrets, ved at en veske, som kjemisk rent vann e.l., som energibærer i en lukket rørsløyfe, pumpes ned gjennom tomt og forlatt borehull fra en fast eller flytende olje-/gassinstallasjon offshore og videre gjennom en avviksboret ny sløyfe horisontalt gjennom reservoarformasjonen frem til et annet tomt og forlatt borehull for deretter oppstrøm til samme installasjon.
På plattform er det installert en binær høytrykks ammoniakk-basert lukket varmeveksler-krets. Den overfører geotermisk energi ved hjelp av varmeveksler,dampgenerator, kondenser med varmepumpe fra havet og dampturbingenerator (re-heat-expander) til elektrisitet som er nok til at energikretsen er selvdrevet og plattformen er netto elektrisitets-produsent, med fremstilling av ren elektrisitet uten miljøforurensing fra jordens indre vedvarende geotermiske kilde.

Den nedpumpede kalde veske vil ved sin passasje i den geotermiske sløyfe i et felt 3500 - 6000 meter under havbunnen bli tilført geotermisk varme-energi i temperaturområdet 90 - 150 0 C, og vesken vil ved å fremføres i separat oppstrøms rør unngå vesentlig varmetap. Derved unngås det vanligste problem ved parallelt anlagte opp- og nedstrøms-rør, der varm veske på sin vei opp blir nedkjølt av kald veske på vei ned; et forhold som ødelegger effekten oppe på plattformen.

Et stort antall borehull er alt i dag forlatt fordi olje- og gasskildene er uttømt med dagens teknologi. Senere kan ny teknologi pány gjøre disse drivverdige dersom mulighetene i dag tilrettelegges og plattformene befinner seg på feltene. Disse borehullene er boret til priser opp til NOK 25.000 pr. løpemeter. Dersom 2 hull @ 3000 meter tas i bruk, representerer disse en verdi på NOK 150 mill.
Ved å avviksbore et nytt 1000 meters horisontalt hull nede i feltet mellom de to forlatte hull, blir prisen for dette siste hull estimert til NOK 20 mill med ny boreteknologi. Prosjektet omfatter da således 7 km borehull til en verdi av ca. NOK 170 mill i en lukket sløyfe for fremføring av termisk energi til plattform. Eksempelvis vil Statfjord B med ca. 40 brønner bli nedlagt ca. år 2003 men representerer alene kanskje 20 geotermiske sløyfer i fremtiden.

Fordi feltet er " tomt " vil plattformen også måtte forlates, og det vil koste store summer å fjerne en slik plattform. Antydningsvis vil fjerningen av alle plattformer i Nordsjøen i dag koste mellom NOK 50 - 70 milliarder.
Ved å installere det nødvendige varmevekslerutstyret for dampproduksjon med omforming til elektrisitet, vil plattformer som ellers skulle vært forlatt og fjernet, forbli vedvarende inntektsgivere ved salg av elektrisk energi via sjøkabler til andre plattformer og til lands med fordeling på det vanlige strømnettet.

I dag er lavtemperert geotermisk energi benyttet med hell i anlegg på land, men ennå ikke på plattformer offshore.
På land har de naturlige varme kildene, som finnes i nærheten av vulkkaner, blitt benyttet til å dekke varmebehov til menneskene i mange år. Det er først i de 10 siste år at det er gjort store fremskritt i geotermisk varme-energi fra både veskereservoar i jordens indre og fra varmen langt nede i grunnfjellet (gneis) som er oppvarmet av magmaen i jordens indre. Det utføres forskning ved flere prøveanlegg på land.
Ennå er lite gjort for å utnytte geotermisk varme-energi til elektrisitet, men det finnes slike kraftstasjoner i dag som viser meget gode resultater i drift over mange år.
Denne formen for energiutnyttelse er bl.a. av USA's National Federal Strategy blitt utpekt til å være den på kort sikt største kilde til å forsyne USA med fornybar energi. I USA ble " Geothermal Energy Program" startet i 1971 med mindre enn 200 MW av slik energi i operasjon. Det var først og fremst alle kildene til tørr-damp fra Geyser i Nord-Californial som utgjorde mengden. Problemene med energi fra varme vesker i jordens indre var mange. Kjemiske stoffer og etsende vesker gjorde at bl.a. bladene på turbinene ble ødelagt.
Utviklingen gikk raskt, og i 1991 var elektrisk energi fra Geyser nevnt ovenfor, blitt til verdens største kompleks av geotermisk energiutnyttelse med en produksjon av 1500 MW elektrisitet ved 25 anlegg. Ved siden av dette opererte det 40 anlegg andre steder i USA med tilsammen 820 MW produsert elektrisk energi fra varme veskekilder. USA's National Energy Strategy mener at geotermisk fornybar energi vil i USA bli mer enn 10 ganger større frem mot år 2010. Vi må kjenne til at i USA utgjør alle former for fornybar energi i 1990 bare 8 % av nasjonens energiforbruk. Resten er energi som forbrukes en gang for alltid.

US Department of Energy (DOE) har i 1991 utgitt sitt "Programs in Utility Technologies" over temaet "Geothermal Energy - Program Overwiew" hvor disse opplysningene er hentet fra.

Island har utnyttet sine varme kilder som Geysir ved Reykjavik til oppvarming av hus og til varmt vann for bruk i industrien. I de senere år er varmt vann også benyttet til å skape elektrisk energi. Et slikt anlegg ligger i dag i Nesjavellir på Island. Når dette energiverket er ferdig utbygget vil det kunne produsere opp til 43 MW elektrisk energi, men beregnet gjennomsnitt på 7000 timer/år er 30 - 37 MW elektrisk energi. Strømprisen er i 1992 beregnet til US$ 0,008 pr. kWh. Dette er langt lavere enn hva strømprisen er fra et vannkraft energiverk på Island i 1992, som er US$ 0,018 pr. kWh.

Andre anlegg for geotermisk varme-energi til elektrisk energi finnes i dag bl.a. i Italia, Mexico, Guatemala, Hawai og Fransk Vest-India.
I Europa ytes det støtte til forskning på energi fra varme steinformasjoner i jordens indre. (HDR = Hot Dry Rock) Forskning på dette foregår i Tyskland, men er ennå ikke kommet til praktisk utnyttelse. Det er forbundet med store borekostnader på dype brønner (6000 meter) i gneis og uten mulighet til å bringe geotermisk varme rimelig opp til overflaten. Borekostnadene er gjerne 4 - 5 ganger så høye sammenlignet med kjent teknologi for olje- og gassbrønn-boring i dag.
I Norge har vi lite eller ingen erfaring med geotermisk energi. Det er gjort endel beregninger i Oljeindustrien på å utnytte den varme som kommer opp med oljen og vannet fra oljefelt. Den er ikke funnet drivverdig til å skape elektrisitet fordi det inntil omsøkte patent vil kreve for store energimengder å få denne varme-energi opp av oljebrønnene og ville bare fordyre oljeproduksjonen.
Den Europeiske Union (EU) gir støtte til dette forskningsprogrammet hvor Norge bl.a. gjennom EØS-avtalen har bidradd med pengestøtte. Det vil således bli søkt om støtte også til dette prosjekt fra EU.
I Norge har vi gjort store fremskritt med å skape energi i form av varme lagret i veske gjennom varmepumper. Her kan nevnes fiskeoppdrettsanlegg og papir-/cellulose-industrien samt endel fjernvarmeanlegg til større offentlige bygg. Bodø Hovedflyplass er i dag oppvarmet med energi fra varmepumper fra sjøvann i fjorden. Dette er viktig med tanke på den utnyttelse slike varmepumper og varmevekslere har i prosjektet med geotermisk varmeenergi. Det er derfor i Norge og de andre skandinaviske land i dag, en godt utbygget industri på produkter til anvendelse i geotermisk energi. Grunnlaget finnes for å skape en ny vekstindustri på dette felt i Norge gjennom å satse på fornybar elektrisk energi fra kilder som i dag finnes lagret i våre olje- og gassfelt i Nordsjøen, og der vi disponerer et stort antall ferdig-borede hull som etter feltets utnyttelse ikke lenger har noen verdi, men tvertimot koster betydelig å avvikle.

Eksempel:
Beregninger foretatt på anerkjente programmer for å beregne energibalanse i rørsystemer i offshore oljeindustri, viser at det er et stort energioverskudd gjennom den lukkede geotermiske krets gjennom det tidligere olje- og gassfelt. Det er også store forskjeller ved valg av rørdiameter.
Beregningene viser den teoretisk maksimale energi som primærkretsen kan bringe med seg opp på plattformen.

	ø8"	ø10"	
indre diameter:	173,1 mm	215,8 mm	
vannmengde:	700 m3/t	700 m3/t	egenvekt 1,014kg/dm3
vannets hastighet:	8,26 m/s	5,32 m/s	200 l/s
temp. nedstrøm	16 gr.C	16 gr.C	/40 gr.C (forran/bak pumpen)
temp. oppstrøm	90 gr.C	90 gr.C	
lengde rørsløyfe totalt:	7000 m	7000 m	(2 x 3000m vert. + 1000m hor.)
trykkfall i sløyfa:	197 bar	63 bar	
pumpe energi:	5,4 MW	1,72 MW	virkn.grad = 0,75
varmeenergi opp:	40 MW	40 MW	

Rett til endringer i beregningene forbeholdes.

Denne energien kan via binære varmevekslere, dampgeneratorer og varmepumper fra havet bli omformet til damp som igjen styres inn på dampturbiner (expandere med reheat) for å drive de elektriske generatorene plassert på platformen. Dampen tilbakeføres via kondensere og resirkulerer i det lukkede systemet.

Erfaringer på etterhvert mange varmeomformere av den binære typen med høytrykk (40 bar) ammoniakk (NH3) brukt på slike geotermiske varme-energiverk, viser at det skal ca. 8 deler varmeenergi til for å skape 1 del elektrisk energi.

Beregnet elektrisk energi: $\frac{40 \text{ MW}}{8} = 5 \text{ MW}$

Relatert til Statfjord B med 40 brønner, kan dette gi 20 geotermiske sløyfer som da gir tilsammen 5 MW x 20 = 100 MW elektrisk energi

Til sammenligning er Norges største generatorer i vannkraftverket Svartisen på 350 MW

Det fremgår herav at det er elektrisk energi til pumpene som drar avsted med største delen av energien på plattformen. Eksemplet ovenfor viser at en 10" rørledning kan gi netto energi på sløyfen, lik 5 - 1,72 MW = 3,28 MW elektrisitet.

Her må alle fremtidige vurderinger av delene i prosjektet føre til kanskje enda bedre utnyttelse av den geotermiske energien.

Med teoretisk kontinuerlig drift i ett år, vil dette tenkte fremtidige Statfjord B geotermiske energiverk med 20 sløyfer frembringe:

20 x 3,28 MW x 365 x 24 t = 566,8 GWh

Vi kan stipulere salgsprisen på elektrisitet inkl. linjekostnader og avgifter til ca. 40 øre / kWh, som gir en stipulert strømpris til kraftverket på ca. 25 øre/kWh.

Statfjord B geotermiske energiverk vil pr. år selge strøm for

566,8 GWh x 0,25 = NOK 141,7 mill.

- Prisene på elektrisk kraft er til sammenligning 3 - 5 ganger høyere ved leveranser på dagtid til det europeiske marked.

Del 2

Stavanger, 30 mai 1995

Tegninger eller skisser.

Fig.1
Fra den utrangerte olje- og gassplatformen (1) skal brønnene (2) (4) og gjerne mange flere, utnyttes til å utvinne lavtemperert geotermisk varme-energi ved å avviksbore (16) fra den ene brønnen til den andre, slik at det dannes flere rør-sløyfer (3). Det skal innsettes et rør gjennom hele sløyfen (3) som skal lede en kjemisk ren veske, vann e.l. i en lukket krets opp på platformen (1). Vesken pumpes med elektrisk drevne pumper (5) med en slik mengde og hastighet, at den geotermiske varmeenergi blir overført til vesken og ført opp (4) til platformen gjennom den lukkede sløyfen (3). Denne varmeveksling er optimalt tilpasset den geotermiske varmetilførsel.
Alt etter hvilke forlatte borehull som blir utnyttet, må den avviksborede sløyfen (3) gå så dypt som 3500m til 6000m under havbunnen.
Dette er normale dybder på borehull som finnes for olje- og gass i Nordsjøen. Praktiske målinger viser at vi får opp vann med temperaturer fra 90 gr.C til 160 gr.C fra slike brønner.
Den beskrevne rørsløyfen (3) er sikret med ventiler i casingene for nedstrøm (2) og oppstrøm (4) samt med BOP. på platformen under avviksboringen av sløyfen (3) og senere når vesken skal pumpes gjennom sløyfen. Normalt skal det ikke kunne skje utplåsinger i den lukkede sløyfen (2) (4).
Det skal utvikles en spesial rørtype for sløyfen (3).

Fig.2
Figuren viser skjematisk en alminnelig kjent funksjon til et termisk energiverk.
Den forlatte platformen (1) er ombygget på dekket. Boretårn (16) og boligmodulen er benyttet, men tilpasset det nye behovet. Et modulbygget varmeenergiverk er plassert på dekket.
Pumpene (5) sørger for konstant strøm av veske gjennom den lukkede sløyfe (3) opp til platformen (1). Den kjemisk rensede og steriliserte vesken, som vann e.l., skal leveres i tank fra industrien på land. Den varmeenergien som vesken (90 - 160 C) inneholder, blir overført gjennom lavtrykk (1 bar) varmevekslere (6) for så å drive en høytrykk (40bar) amoniakk (8) varmepumpe (7) før den gjennom kondensere (15) og kjøling går tilbake i rørsløyfen og samme vesken pumpes (5) pånytt ned (2) med en temperatur på ca. 15 gr.C. Fra høytrykk amoniakk varmepumpen (7) blir det tatt ut damp i en dampgenerator (9) og kjele (10) til å drive dampturbinene (11), av typen reheat expandere, før dampen går tilbake via kondensere (15) og pumpes (7) pånytt i den binære kretsen for høytrykk amoniakk. Hele kretsløpet i den binære sløyfen er lukket.
Dampturbinene (11) driver den generatoren (12) som skaper elektrisitet. Endel av denne elektrisitet må benyttes på platformen for å drive alle pumpene (5) (7) og til normale forbrukere som lys. Oppvarming i boligmodulen skjer fra varmepumper.
Elektrisk energi blir via høyspenning teknikk (13) og sjøkabel (14) overført til forbrukerene på andre operative olje- og gassplatformer eller til kraft-nettverket på land (18) (19).

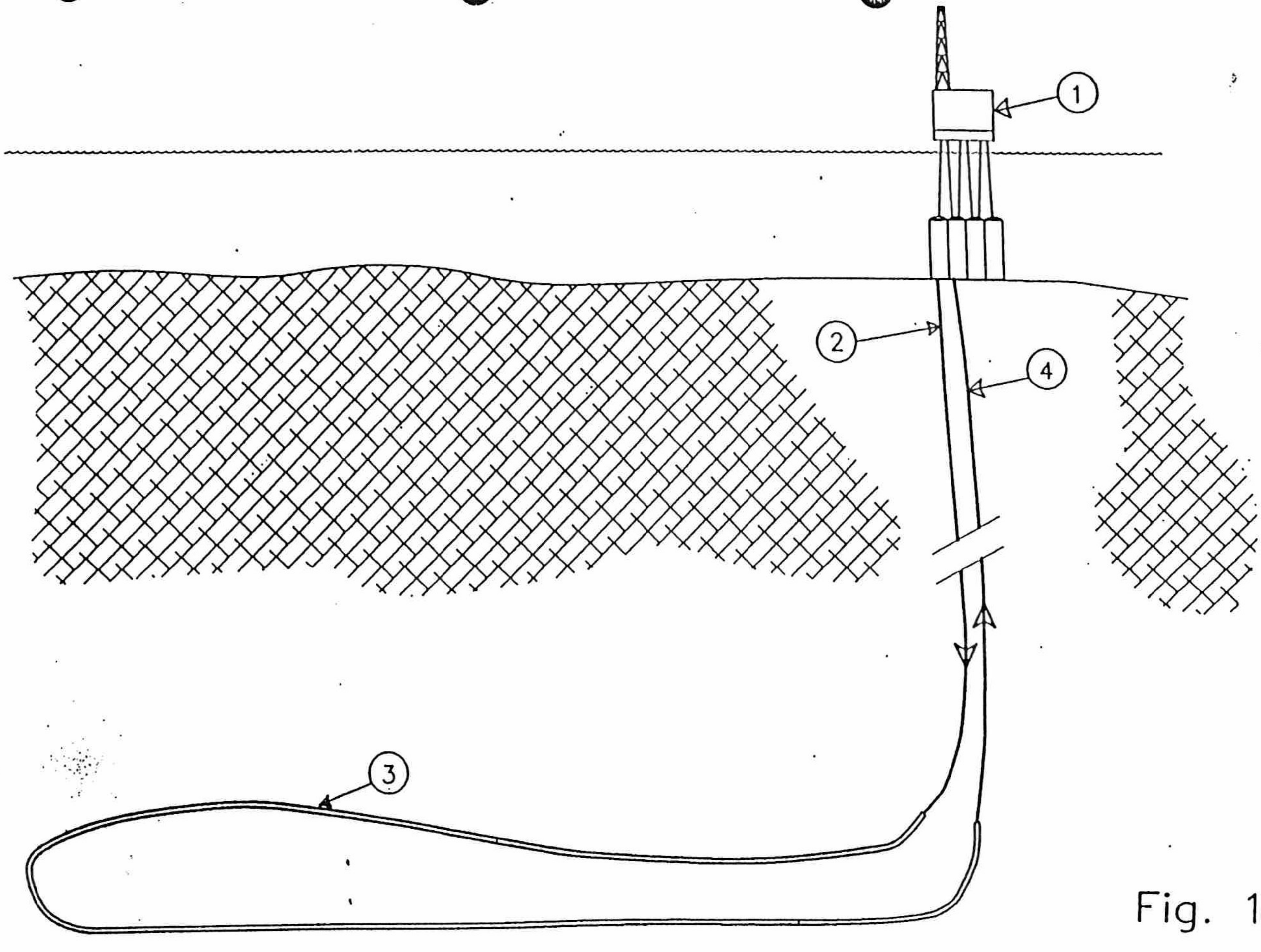

Fig. 1

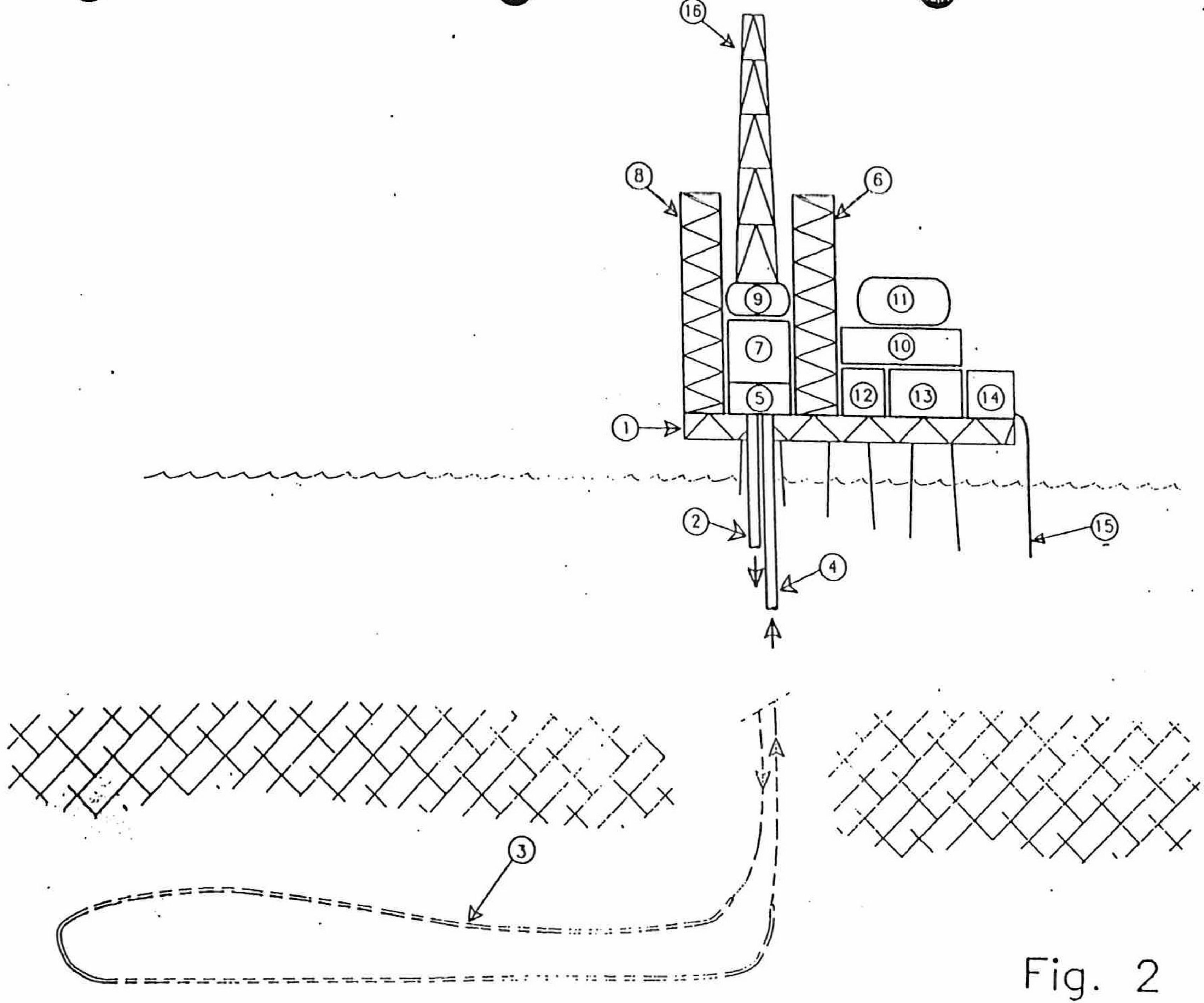

Fig. 2

Sammendrag

Oppfinnelsen angår en metode for bruk av geotermisk lavtemperatur lukket energikrets ved at det bores et nytt horisontalt hull (3) mellom to vertikale tomme borehull (2), (4) som skal forlates.
Med pumpekraft (5) etableres nedstrømming av kald veske som kjemisk rent vann e.l. i ett borehull (2) fra plattform (1) omgjort til energiomformer-enhet. Vesken passerer videre gjennom den nye horisontale down-shore sløyfe (3) beliggende 3 - 6000 meter under havbunnen, der den varmes opp av omsluttende områders geotermiske varme-energi, hvoretter oppstrømming (4) av oppvarmet veske til plattform avslutter det lukkede kretsløp.
Ved høytrykks ammoniakk-basert (9) lukket, binær varmevekslerkrets (6),(7) overføres energi via dampgenerator (10), varmepumpe (5) fra havet og dampturbiner (12) for fremstilling av elektrisitet fra jordklodens indre vedvarende geotermiske kilde, uten forurensing av noen art.
Kondensere (8) sørger for gjenvinning av veske fra damp som tilbakeføres i sin lukkede sløyfe.
Gjenbruk av etablerte borehull til tømte reservoarer, og videreføring av plattformer til geotermiske energiverk for elektrisitet med sjøkabling (15) til andre offshore-installasjoner og til kontinentet via etablert fordelingsnett, vil kunne gi betydelige og vedvarende inntekter fra de betydelige og nedbetalte investeringer i olje- og gass-utvinningsmiljøet, utnytte dag-natt pris-sykler, ved å drive pumpeverk med billig nattkraft, og bidra betydelig til fremtidens energiforsyning innenfor miljøvennlig fornybar energi.

Merk:
ELI AS som er eierselskapet av ELI. (pat.pending), vil gjerne invitere til industrisamarbeide for at et ELI.-prosjekt skal bli realisert.
Vi ønsker kun seriøse interessenter. Det forventes derfor at all informasjon om ELI.-prosjektet og et fremtidig samarbeide blir behandlet konfidensielt. Derfor er det vedlagt et forslag til fortrolighetsavtale som ELI AS vil ha undertegnet med firmastempel.
ELI.-prosjektet er beskyttet gjennom pat.pending P950306 Styret for industriell rettsvern.

Stavanger, 2.februar 1995

Med vennlig hilsen for ELI AS

Einar Langset

Einar Langset

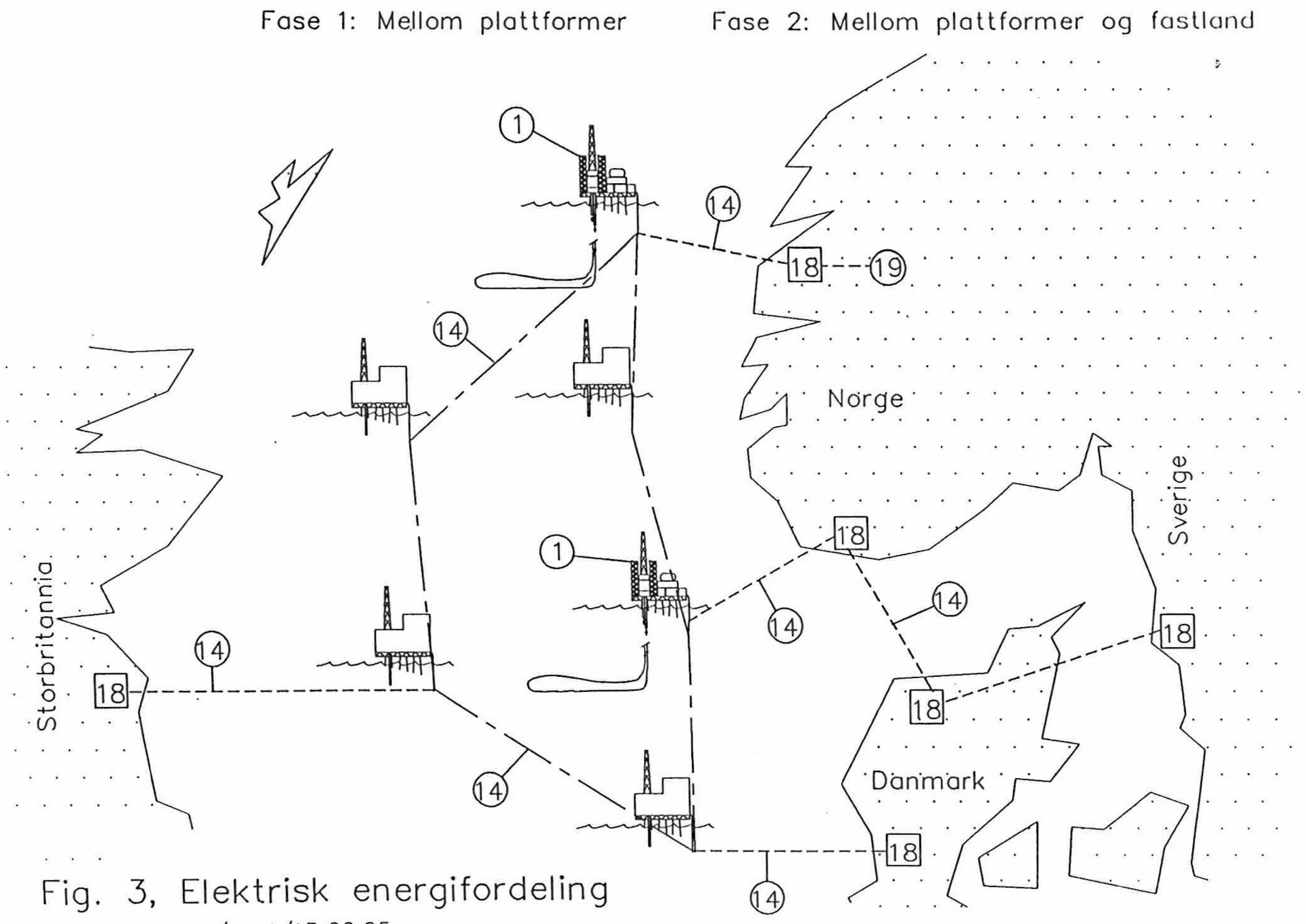

Fig. 3, Elektrisk energifordeling

RN/ANN/13.06.95

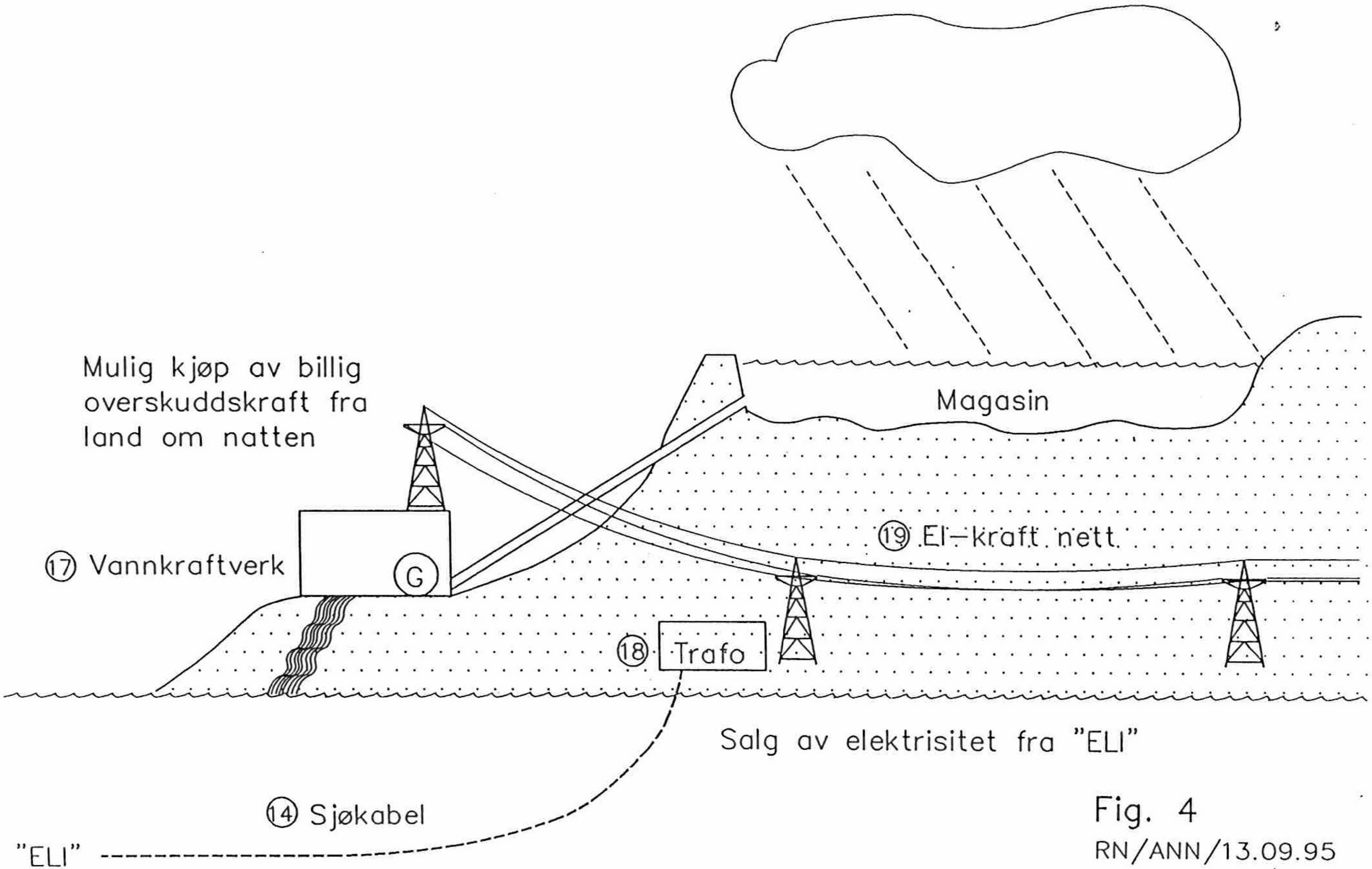

Fig. 4
RN/ANN/13.09.95

Appendix B: NFR - Final report

Årsrapport 19 95.

For brukerstyrt og næringslivsrettet FoU

Norges forskningsråd
Boks 2700 St. Hanshaugen
N-0131 Oslo
Telefon 22 03 70 00

Prosjekt/seksjonsnr: 32897/212

Prosjekttittel: GEOTERMISK EL-KRAFT OFFSHORE

Kontraktspartner: RF-Rogalandsforskning, P.B. 2503, Ullandhaug, 4004 STAVANGER

RESULTATDOKUMENTASJON (Dersom det i perioden er fremkommet et delresultat som kan belyse prosjektets nytteverdi, skal dette beskrives på maks 10 linjer. Beskrivelsen må være i en enkel journalistisk form egnet for offentliggjøring i Forskningsrådets årsberetning, informasjonsblad o.l.)

Et patentsøkt konsept (ELI-konseptet) for utnyttelse av olje/gass-brønner og -installasjoner i Nordsjøen til miljøvennlig og fornybar produksjon av elektrisitet har blitt vurdert teknisk og økonomisk. Prinsippet utnytter jordvarme ved å sirkulere væske i en lukket sløyfe knyttet til et kraftverk på en plattform. De foreliggende beregninger viser at en 10" brønnsløyfe etter 5 års drift vil produsere en varmeeffekt på maksimalt 350 kW per km brønnlengde når temperaturforskjellen mellom den kalde væsken og det varme fjellet er 100 °C. Denne lave effekt vil medføre svært høye produksjonskostnader på den elektriske kraft. Hovedtyngden av kostnaden er knyttet til boring av brønner. Konseptet vil derfor kunne bli interessant i Nordsjøen bare dersom borekostnadene kan reduseres med en faktor på minst 10, samt at driftskostnadene må være svært lave. I områder med høyere temperatur i berggrunnen vil energien kunne utnyttes mer effektivt, og konseptet vil være mer interessant.

Har forskningsarbeidet utført i perioden avvik i forhold til kontraktfestet arbeidsplan?

Ja [ ] Nei [x]

Periodens kontraktsfestede delmål/milepæler er nådd:

Ja [x] Nei [ ]

Nærmere redegjørelse for status og avvik er gitt på de etterfølgende sider (som alle er merket med prosjektnr. og -tittel). Rapportering følger den disposisjon som er spesifisert på baksiden av dette skjema.

24/1-96 — Dato

Bjørnar Lund — Prosjektleder

02/94

Rettledning for rapportutforming er gitt på baksiden.

1. Problembeskrivelse og målsetting

Med bakgrunn i dagens olje- og gassutvinning i Nordsjøen og nedbygging av deler av denne i nær framtid, vil problemstillinger rundt plattforminstallasjonene melde seg. Fjerning av disse vil koste betydelige summer og alternative bruksområder for plattformene er under vurdering. En mulig utnyttelse av slike plattformer vil være kraftproduksjon basert på geotermisk varme.

Prosjektet har gjennomført en evaluering av ELI-konseptet (pat. pend. 950306), ved å foreta tekniske og økonomiske beregninger basert på et kraftverk knyttet til tenkte brønnpar (brønnsløyfer) i Nordsjøen. Dette konseptet er utarbeidet av ing. Einar Langset i firmaet ELI A/S og utvinner geotermisk energi ved å sirkulere en væske (primærvæske) i brønnsløyfene.

Data som er brukt er representative for forholdene i Nordsjøen, men er ikke hentet fra konkrete installasjoner eller felter.

Prosjektet har vært utført ved Rogalandsforskning og ved SINTEF Termisk Energi og Vannkraft. I tillegg har prosjektet benyttet konsulenttjenester fra firmaet ELI A/S.

I tillegg til denne årsrapporten, som også utgjør sluttrapport, har RF og SINTEF utarbeidet en utdypende vitenskapelig rapport på engelsk.

2. Motivasjon og teknologisk utgangspunkt

Dette prosjektet har vært motivert ut fra potensialet for konkurransedyktig produksjon av elektrisitet på offshore-installasjoner i Nordsjøen. Man har estimert en nedre grense for pris på produsert elektrisitet for å kunne vurdere hvorvidt konseptet kan være økonomisk realiserbart.

I tillegg har man potensielle økonomiske gevinster på grunn av at kostnader ved fjerning av plattform utsettes i tid. Dette har ikke vært vurdert i denne rapporten. Man har heller ikke vurdert eventuelle gevinster for norsk forskning og næringsliv generelt, eller miljømessige faktorer.

3. Resultater

3.1 Teknologisk analyse av ELI-konseptet.

3.1.1 Bore- og brønnteknologi.

Det antas at teknologien for boring og komplettering av brønnsløyfe (primærkrets) er tilgjengelig, og dette har ikke vært studert nærmere. Arbeidet har vært konsentrert om varmetransport mellom formasjon og varmebærende væske, inkludert nedkjølingen av formasjonen.

I disse beregninger har analytiske metoder blitt brukt, bl.a. for å fastslå konseptets potensiale, og hvorvidt mer ressurskrevende numeriske beregninger kan forsvares økonomisk. I det følgende beskrives forenklinger som har vært gjort for å kunne foreta analytiske beregninger for å finne en øvre grense for instantan varmeeffekt per lengdeenhet som funksjon av tid.

Beregningene har blitt utført for en tenkt brønn med to vertikale seksjoner forbundet med en horisontal seksjon. En har antatt at de forskjellige deler av brønnen iløpet av levetiden til anlegget ikke påvirker hverandre termisk, p.g.a. de lave verdier av termisk konduktivitet i bergarter.

Beregningene for varmetransport i formasjonen tar hensyn til konduksjon i bergartene. Konveksjon p.g.a. formasjonsvæske har liten betydning i Nordsjøen, og er neglisjert[1]. Varmeovergangen til primærvæsken antas å skje ved konveksjon i primærvæsken. Varmetransport i formasjonen p.g.a. stråling er ubetydelig i forhold til transport ved konduksjon, og har blitt neglisjert.

En øvre grense for instantan varmeeffekt per lengdeenhet har blitt beregnet ved hjelp av en kvasi-stasjonær approksimasjon. Gyldigheten av denne approksimasjonen har blitt verifisert ved å sammenligne med eksakte analytiske løsninger av lignende problemer.

Denne øvre grense er beregnet ved å anta 1) maksimal forskjell mellom primærvæskens temperatur og temperaturen i formasjonen, 2) maksimal termisk ledningsevne og 3) minimal termisk motstand i foringsrør, sement og den effektive motstand på grunn av konveksjon.

Figur 1 viser den beregnede øvre grense for total varmeeffekt per lengdeenhet for tre forskjellige rørdiametre. Formasjonens tetthet, termiske konduktivitet k og varmekapasitet c er her henholdsvis 2670 kg/m^3, 2.65 (W/°C·m) og 895 J/(°C·kg)[2]. Merk at varmeeffekten avhenger lineært av differansen mellom temperaturen i formasjonen og temperaturen til primærvæsken. Videre har rørdiameteren ikke stor innvirkning på varmeeffekten.

En tilsvarende øvre grense for total varmeeffekt oppnås ved å multiplisere denne verdien med lengden av den delen av primærkretsen som ikke er termisk isolert (man vil ønske å isolere deler av røret som fører væske opp til overflaten for å unngå varmetap).

Pumpearbeidet er ikke tatt med i disse beregningene da man bare har vært interessert i å beregne en øvre grense for varmeovergangen fra formasjonen til primærvæsken. Bare en del av det mekaniske pumpearbeidet vil gjenvinnes som friksjonsgenerert termisk energi i primærsløyfen. Dessuten vil denne friksjonsgenererte termiske energi føre til at varmeovergangen fra formasjonen reduseres. Nettoresultatet er en forverret energibalanse i forhold til en (tenkt) situasjon med friksjonsløs strømning.

3.1.2 Kraftproduksjonssystemer

For de aktuelle temperaturer (ca 110 °C) på primærvæsken anbefales binære systemer med ammoniakk som væske i sekundærkretsen. Direktevirkende kretser er bare aktuelt ved temperaturer over 160 °C. Binære systemer har blitt bygd for temperaturer ned til 90 °C. Temperaturen på primærvæsken er imidlertid vesentlig med hensyn på virkningsgrad for kraftprosessen, og det bør tilstrebes å finne områder med så høye temperaturer som mulig. Ved geotermiske temperaturer høyere enn 110 °C (valgt som basis her) vil virkningsgraden øke og spesifikke investeringskostnader vil avta. Dette betyr at valg av systemer må vurderes i hvert enkelt tilfelle for fastsetting av endelige produksjonskostnader.

Et case studium har vært utført for et kraftverk med nettoeffekt på 5 MW og med ammoniakk som sekundærvæske. Utgangspunktet har vært en kraftprosess med ett trykknivå med en temperatur på 110 °C og 54 °C på h.h.v. innløpende og utløpende primærvæske fra varmeveksleren.

Sensitivitetsstudier har vært utført for følgende parametre som funksjon av temperaturen til innløpende primærvæske og som funksjon av temperaturen til utløpende primærvæske: virkningsgrad, exergi virkningsgrad, geotermisk varme absorbert i sekundærkretsen, massestrøm av ammoniakk, massestrøm av primærvæske. Mengden geotermisk varme absorbert i sekundærkretsen kan økes ved å redusere temperaturen til utløpende primærvæske, men dette medfører redusert virkningsgrad men samtidig økt exergivirkningsgrad for kraftprosessen isolert sett. Reduksjon av temperaturen for utløpende primærvæske krever mindre massestrøm av primærvæske men samtidig økt massestrøm av sekundærvæske, og følgelig større dimensjoner på varmevekslerne.

Det har også blitt utført en sammenligning av fire forskjellige binære systemer for en temperatur på 110 °C på innløpende primærvæske. I tillegg til kraftprosess med ett trykknivå har følgende systemer blitt vurdert: kraftprosess med mellomoverheting, to-trykks kraftprosess og to-trykks kraftprosess med mellomoverheting. Sammenligningen har vært utført med hensyn til de samme parametre som nevnt ovenfor.

I ovennevnte sammenligninger har en ikke tatt hensyn til nødvendig effekt for å drive kjølevannspumpe til kondensatoren og for å drive pumpe i primærvæsken. En mer inngående analyse som inkluderer nødvendig effekt til kjølevannskretsen har vært utført for kraftprosess med mellomoverheting og to-trykks kraftprosess Denne analysen viser at 20 til 30 prosent av kraften produsert i kraftverket går med til å drive kjølevannspumpen på grunn av at det blir høy løftehøyde av sjøvann opp til platform dekket. Alternativt kan condensatoren plasseres ved sjønivå eller senkes ned i sjøen. Dette vil redusere kraftbehovet i kjølevannskretsen til 5 - 9 % av kraften produsert i kraftverket, men samtidig vil dette kreve spesielle installasjoner.

Basert på ovennevnte analyser forventes et geotermisk kraftverk med temperatur på 110 °C til innløpende primærvæske å ha en virkningsgrad på maksimalt 7.5 % avhengig av effektbehov for pumper til primærvæske og kjølevann for sekundærkretsen med en kondensator ved sjønivå. Alle virkningsgrader er basert på maksimalt tilgjengelig varmemengde fra primærvæsken. Maksimal varmemengde innebærer en nedkjøling av primærvæsken til omgivelsestemperatur. Nødvendig pumpearbeid i primærkretsen er meget avhengig av varmeovergang mellom primærvæska og geotermisk varmekilde. Det er imidlertid viktig å påpeke at virkningsgraden for kraftverket vil øke ved høyere temperaturer på den geotermiske væsken. Ved en temperatur på den geotermiske væske på 190 °C kan det ventes en virkningsgrad på maksimalt 12 % avhenging av kraftbehov i forbindelse med pumping av geotermisk væske.

Beregninger fra en produsent av geotermiske kraftverk[3] for et kraftverk på 5MW gir en total vekt på ca. 150 tonn og leveres i 5 til 6 ISO 40 fots containere. Dette kraftverket opererer ved en temperatur på 110 °C på primærvæsken, og har en virkningsgrad på 4 %.

3.2 Økonomisk analyse av ELI-konseptet.

Man har her estimert en nedre grense for realistiske kostnader basert på et sett brønnsløyfer med total lengde 11 km, derav 5 km lengde i en vertikal dybde på 3000 m.

3.2.1 Kostnader ved boring, komplettering og vedlikehold av brønnsløyfe.

En analyse av borekostnader i forbindelse med boring og komplettering av en brønnsløyfe har blitt utført av et serviceselskap på oppdrag fra ELI A/S. Analysen tar utgangspunkt i 5439 m eksisterende brønner med 13 3/8" foringsrør, boring av 5889 m 12 1/4" hull, og komplettering av hele brønnbanen med standard 9 5/8" foringsrør. Totale kostnader ble estimert til kNOK 75256, inkludert borekostnader på NOK 8500 per meter. Borekostnader har vist synkende tendens de siste årene, og forventes å reduseres ytterligere med innføring av ny teknologi (bl.a. tynnhullsboring). I estimatet her er det brukt 50 MNOK som en nedre grense for kostnad ved boring og komplettering av et brønnpar.

3.2.2 Kostnader ved bygging og vedlikehold av binært kraftverk på plattform.

De forventede investeringskostnader for et binærkrets kraftverk på en offshore-installasjon er i dette studiet estimert til å være USD 3500/kW. Kostnaden er relativt høy på grunn av den lave temperaturen til innkommende primærvæske, og fordi offshore installasjon krever spesielt utstyr og sikkerhetsinstallasjoner. Variable driftskostnader er knyttet til bl. a driftpersonale og forsikringer. Totalt gir dette en pris på 40 til 45 øre/kWh isolert for kraftverket ved 7500 driftstimer pr år.

3.2.3 Totaløkonomi for ELI-konseptet realisert i Nordsjøen

En har, basert på resultater fra dette studium, estimert en nedre grense for pris på elektrisitet produsert i Nordsjøen ved hjelp av ELI-konseptet. Beregningene er foretatt for 35 sløyfer à 11 km lengde og tverrsnitt 10". Her har man antatt en uniform temperaturdifferanse mellom formasjon og væske på 50 K langs hele sløyfen, noe som gir en øvre grense for termisk effekt på 1.9 MW_t per sløyfe, og en temperatur på 110 °C til primærvæsken som strømmer inn i varmeveksleren. Med en virkningsgrad på 7.5 % gir dette 144 kW_e per sløyfe eller ialt 5 Mw_e for 35 sløyfer. Levetid for anlegget er satt til 25 år og renten er 7 %. De faste kostnader knyttet til boring og komplettering gir da en pris på 3.4 kr/kWh ved kontinuerlig drift. I tillegg kommer variable kostnader knyttet til vedlikehold av brønnsløyfe og plattform. Sammen med kostnader under punkt 3.2.2 gir dette en nedre grense på nærmere 4 kr/kWh. Flere optimale forutsetninger er brukt, og de reelle kostnadene vil derfor alltid være høyere. Ved å øke temperaturen på primærvæsken vil man kunne øke virkningsgraden. Dette vil imidlertid også øke borekostnadene p.g.a. boring til større dyp og/eller p.g.a. problemer ved boring ved høye temperaturer.

4. Konklusjoner

Beregningene i dette studiet viser at prisen på el-kraft produsert på en Nordsjø-installasjon ved hjelp av ELI-konseptet vil bli svært høy i forhold til typiske priser på el-kraft i Norge. Dette skyldes både den relativt lave termiske effekt som kan produseres, lav virkningsgrad ved aktuelle temperaturer på væsken i primærsløyfen, og høye anleggs- og driftskostnader. Beregningene for termisk effekt er dessuten basert på et idealisert "best case". Virkelige anlegg vil alltid produsere mindre termisk effekt. Hovedtyngden av den estimerte kostnad er knyttet til boring og komplettering av brønnsløyfen.

Geotermisk er en miljøvennlig, og en svært stor potensiell energikilde. For at utvinning av denne energikilden ved hjelp av ELI-konseptet skal kunne bli lønnsom, bør forskning og utvikling for dette konsentreres om utvikling av mer kostnadseffektiv bore- og brønnteknologi.

Når man bare tar hensyn til de forhold som er vurdert i dette forprosjektet (jfr. Kap. 2, punkt1), må man kunne konkludere at ELI-konseptet som studert her idag er for dyrt for anvendelse i Nordsjøen. Utvinning av geotermisk energi ved hjelp av lukkede sløyfer vil ha bedre lønnsomhet på land, hvor bore- og vedlikeholdskostnadene er lavere, samt i geologisk aktive områder. Borekostnader viser imidlertid en klart synkende tendens, og man kan forvente økende priser på elektrisk kraft.

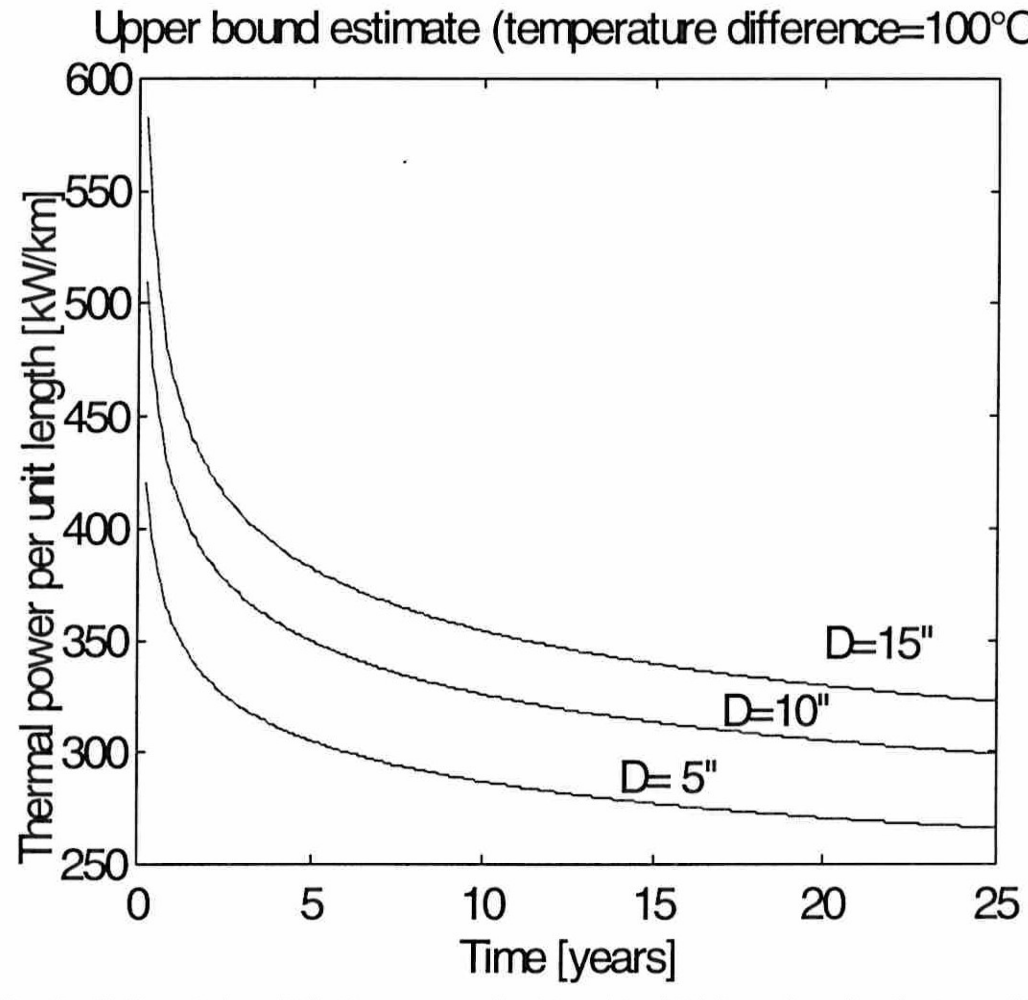

Fig. 1. Estimert teoretisk øvre grense for termisk effekt per lengdeenhet overført fra formasjon til rørsløyfe ved en temperaturdifferanse på 100 °C.

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[1] Edvard Prestholm (Rogalandsforskning), privat kommunikasjon.

[2] Kalksteinsprøver fra 3.5 km dybde i Nordsjøen. Edvard Prestholm (Rogalandsforskning), privat kommunikasjon.

[3] Ormat "Indicative data for geothermal power plant as response of an inquiry" Dec. 27, 1995.