# Final report

Termisk Lagring (HTES)

J.no 64016-0014


Prepared by: Jesper Peter Menne Baunsgaard, Ross DK



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# 1 Background

The project group has been investigating the potential for seasonal heat storage to widen the possibilities for green energy technologies. The project is rooted in few distinct sources. The DSF report 'Status and recommendations for RD&D on energy storage technologies in a Danish context[1]', the project 'Kortlægning af mulighederne for at etablere geologisk varmelagring[2]' and Varmeplan København (see slide 10).

## 1.1 Project goal

The project 'HTES' aims at demonstrating thermal storage in the subsurface chalk/limestones of the Copenhagen area, integration into a practical context in the DH sector and gaining operational experiences with the technology for subsequent commercialisation.

The project is split into three phases, where this report outlines the findings of phase 1.

The scope of the first phase was; review existing knowledge and collect relevant geological and geophysical data from the study area, set up a numerical groundwater and reservoir model leading to a well prognosis complying with standard water well drilling equipment.

## 1.2 Project period

The project ran from 1 January 2017 to 31 December 2017.

## 1.3 Geothermal energy

Geothermal energy is heat from water (brine) reservoirs in the underground and produced to surface via a production well. Heat is extracted through a heat exchanger and the cooled water in injected back into the reservoir via an injection well. The process is cyclic and the water is re-heated and produced again, and again, and …

# 2 Project group

GEUS and DTU Byg has the knowledge of the behaviour and parameters of the limestone sequence (Chalk Group) as well as temperature, depository changes over time as the reservoir is charged and depleted. Ross provides knowledge of well engineering and management, and Geo and Awell have drilling expertise, machinery and not least lab facilities specialised in testing chalk. Ingeniør Huse provides knowledge of surface facilities, and not least heat pumps. OE3i has the systemic knowledge about production planning and optimisation for CHP plants and solar farms.

[1] LINK

[2] LINK

| HTES | | | |
|---|---|---|---|
| **Name** | Company | Email | Phone |
| Jesper Peter Menne Baunsgaard | Ross DK A/S | jesper.baunsgaard@rossoffshore.dk | +45 2673 3073 |
| Jesper Furdal | Awell | jjf@awell.dk | +45 9389 8960 |
| Lars Hjortshøj Jakobsen | Ingeniør Huse | lars@ingenioerhuse.dk | +45 3032 5125 |
| Eric Flyvbjerg | OE3i | eff@oe3i.dk | +45 2199 9344 |
| Lars Kristensen | GEUS | lk@geus.dk | +45 9133 3769 |
| Ida Lykke Fabricius | DTU Byg | ilfa@byg.dtu.dk | +45 4525 2162 |
| Flemming Damgaard Christensen | Geo | fdc@geo.dk | +45 4520 4252 |

Tabel 1 – Project Contacts

The above-mentioned project contacts are at disposal for further deliberation of the project and its results.

## 1.1 Advisory group

The project set an advisory group, which was used to bounce ideas against and to weed out notions, which, in a district heating context, were non-functional.

The group consisted of;

- Project Advisory Group
  - HOFOR
  - Frederiksberg Forsyning
  - Vestforbrændingen
  - CTR
  - Hillerød Forsyning
- Project observers
  - Aalborg Forsyning – Varme
  - Din Forsyning
  - HTK Forsyning
  - DC Commodities

# 2 Executive Summaries

The following reports were the outcome: Surface plants (Ingeniør Huse), Data and model simulations of storage potential (OE3i), Well design (Ross DK), Geotechnics and geology section (DTU), Examining the possibilities of establishing thermal storage in the chalk/limestone aquifer in the greater Copenhagen Area (GEUS) and Business Case Models (Ross). Awell and Geo have supplied input to the reports, but have not reported independently.

## 2.1 Discussion

The project has highlighted a significant lack of consistent data material to fully assess the storage potential. This has been evident in the work conducted by GEUS and DTU and looking at consistency of the geological and geotechnical data. The data from shallower parts of deep wells is usually very limited, e.g. no cores from the target zone exist within the greater Copenhagen area. Besides, no well test data are available from the chalk section in the potential storage zone (400–800 m), meaning that the effective permeability is difficult to address. The data material currently available is thus sparse, and the project team therefore recommends introducing a Phase-2 working period. The objective of Phase-2 is to provide a more comprehensive and thorough dataset.

This has been carried forward to the discussion and analysis of the porosity and permeability of the chalk/limestone sections, and the project team has had very lively discussions on the assessment of both the matrix and the effective permeability. The effective permeability of the target zone is a crucial parameter when assessing the storage potential and possible production and injection rates. Unfortunately, the effective permeability is not known for the time being, but our analyses of the existing data material makes it possible to set up a number of conceptual models with the objective to estimate the storage potential and possible flow rates.

The outcome of the permeability discussions has been an assessment of the flow rates that the wells can sustain in a charge/discharge scenario. The assessment of effective permeability is challenging, and hence potential flow rates thus rely on geological evaluations combined with reservoir simulations. A good geological model is a pre-requisite for running reliable reservoir simulations, and time has therefore been spent on analyzing seismic data, well log data and additional geological information from nearby deep wells. As no cores are cut in the target zone, the assessment of the matrix permeability is based on a common porosity-permeability relationship that has been set up on the basis of core analysis data from shallow wells. The chalk section is subdivided into a number of flow units that differ in terms of geological character and reservoir properties. The unit having the most favourable reservoir properties is the so-called Hvidskud Member located at a depth of c. 600 m.

When using the current geological model, the reservoir simulations performed by GEUS point to a base case production rate of 35 m3/h. A production rate of 50 m3/h (best-technical estimate) is used in the business case model flow models run by Ross DK. The difference in the flow rates used in the two models is due primarily to assumptions made concerning the effective permeability of the chalk.  The permeability assigned in the best-technical estimate business case model is based upon the effective permeability (matrix and fractures) estimates used in numerical models of the historical production of oil and gas from offshore chalk reservoirs. The permeability used in the reservoir simulations is based upon a more conservative view of the effective permeability of the chalk. Nevertheless, the flow modelling results highlight the uncertainty of the chalk permeability estimates and the need for a well test to quantify the effective permeability of the chalk and well performance.

The use of well stimulation and water treatment should be considered. The purpose of well stimulation is to enhance inflow performance and to improve the productivity of each well. The objective of water treatment is to prevent - or at least reduce - clogging, scaling and corrosion problems (observe that appendix 5 discusses the geochemistry of the chalk-water system).

## 2.2 Conclusions

It is the project group's assessment that large-scale seasonal heat storage can be feasible, but potential production and injection rates are difficult to assess based on the available data. Our conclusions are summarized below and further details are given in the appendices;

- Drill a pilot well into the storage zone. The well drilling process should be accompanied by data acquisition: testing, coring, and logging.
- Analyze and describe the cores cut in the pilot well: Measure porosity, permeability, fractures and geotechnical parameters, make core flooding experiments etc.
- Evaluate the well test data and the acquired logs from the pilot well to point out the best layers for thermal storage. The results of the core analyses, well test interpretation and the log interpretation will positively assist in the

decision making on storage design etc. A well test will be essential for assessing the productivity of the storage zone chalk.

- No direct permeability measurements are currently available from the chalk in the storage zone, but the GEUS evaluation of the existing data material points to a matrix permeability of 2 mD and an effective permeability that is 5 times higher than the matrix permeability.
- The water injection leads to increased pressure in the storage zone. The reservoir simulations indicate that this pressure disturbance affects the formation pressure at the base of the groundwater zone to a limited extent. Most likely, the fluid flow in the storage zone does not interact with the groundwater zone.
- No geotechnical tests/data are available from the storage zone, meaning that the elastic moduli, stiffness and strength of the chalk are not known.
- We have considered two prospect types having storage potential: (i) a matrix type like Vestforbrænding and (ii) a prospect located close to a fault zone.
- We have carried out a number of reservoir simulations, including sensitivity studies on potential production rates. These studies are based on various permeability assessments and the use of different well stimulation techniques.

# 3 Surface plants, Ingeniør Huse

The role of the surface plant in the heat storing process is to extract heat from the underground reservoir via a production well, transfer the energy on to the district heating grid and re-pump the geothermal water back into the subsurface via an injection well. The design must, therefore, be adapted to values for flow, temperature, and other parameters from the reservoir and district heating system. It goes without saying that the final design of the surface plant can therefore not be determined until pump tests of all wells have been carried out.

The formation water is pumped up from the formation using an electrical submersible pump. The depth of the pump depends on parameters such as the partial pressure of the dissolved gas, pressure in the reservoir and the lowering of the water table when pumping.

Heat exchangers are used to extracting the heat from the formation water. Due to the high salinity of the formation water the components of the heat exchangers, as well as the pipes and other instruments in the system, must be of materials capable of withstanding this salinity as well as being protected from oxygen.

The biggest expense in the surface plant are the heat pumps, which are used to move energy extracted from the formation. A reduction in the size of the heat pump will, therefore, lead to savings in the cost of the surface plant. Heat pumps can be driven either by heat (absorption heat pumps) or mechanically (electric heat pumps).

Absorption heat pumps are not as flexible as electric driven heat pumps when it comes to placement within the plant as they need access to process heat. Process heat is more economically attractive and if the surface plant is located close to a combined heat and power station (CHP) it is possible to increase the temperatures so they are sufficient to drive the absorption heat pump.

Electric heat pumps are more flexible with regard to placement. The coefficient of performance is higher compared to the absorption heat pumps but they are sensitive to high condensation temperatures. Heat is extracted directly from the heat exchanger, but the temperature will decrease with time and the heat pumps contribute more to the total heat output.

One way of reducing the size of the heat pump is to heat the storage to a temperature higher than the natural temperature in the formation, this will require transferring more heat to the reservoir in the summer and extract less heat initially. Similarly a decline in reservoir temperature will decrease the output from the heat exchanger which the heat pump will have to compensate for and thus increasing the cost.

# 4 Data and model simulation of storage potential, OE3i

The graphics planning and optimization tool Mentor Planner was used to calculate the best operation schedules for power and/or heat-producing plants. Prices for selling power were gotten from the price area covering the eastern part of Denmark (Zealand and Lolland Falster), heat demand was calculated as the average of four different installations, and heat production from solar panels calculations was based on historical weather data averaged from three different locations.

Three production units capable of producing fairly cheap excess heat during summers and save the heat for the winter were simulated; Incineration plant, solar heating plant, wood chip plant.

Incineration plant:

A direct correlation between the size of the thermal storage and the economic output was found, as large thermal storages make it possible to produce and save the heat during the summer at a relatively low cost. The thermal storage should not be larger than the amount of heat that is normally produced by the peak boilers, otherwise, the capacity of the heat storage is not fully utilized.

A large number of simulations were made to show the importance of the transfer rate to and from the thermal storage. As expected, the increase in the profit is reduced as the transfer rate decreases:

- With the max transfer rate of 20 MW or higher, the test incineration performs very well.
- At transfer rates under 5 MW the heat storage cannot be discharged fast enough in the winter, leading to increased usage of peak boilers.
- At transfer rates under 3 MW, the economic performance gets unacceptable.

The influence of heat loss in the thermal storage was investigated, results show that heat loss does not really influence the economics much, but has a moderate effect on the overall profit. The reason for this is that the lost heat is replaced by cheap production from the incineration.

Solar heating plant:

Solar heating plants are usually equipped with a pit-storage which requires a lot of space. Solar panels cannot be switched off when the storage is fully charged as the fluid in the panels would boil. As a result peak boilers have to support the heat delivery in the winter.

Simulations with three different sizes of solar heating plants were performed, and for each size simulations with different heat loss where made. Intermediate results show that larger solar heating plants mean an increase in profit but also larger construction investments and more heat loss in the thermal storage means a moderate decrease in profit.

In sunny hours solar heating plants produce more than the heat demand. The amount of excess heat depends on the size of the heating grid as well as the maximum heat capacity of the solar heating system. Since HTES is not expected to deliver much more than 5 MW heat, there is a need for additional heat storage without any transfer limit that can receive the excess heat fast enough. Due to the limitations of the heat transfer rate, HTES is probably less suitable for use as a seasonable heat storage for solar heating plants.

Wood chip plant:

Similar simulations as for incineration plants were made and gave slightly different values. Results showed that larger heat storage leads to increase in profit, more heat loss leads to a moderate decrease in profit and lower heat transfer leads to significant decrease in profit. Influence of heat loss and transfer rate is higher than for incineration plants.

## 5 Well design, Ross

Two well designs were assessed: a vertical well with a completion length of 500m, and a deviated/horizontal well with a completion section length of 800m.

A deviated well would be far more challenging to drill due to the relatively soft formations at the desired depth. A proposed method from Awell on using a mobile water well drilling rig was assessed. The following risks were associated with the method: water well drilling mixed with directional drilling equipment was not been proven, higher drilling parameters and casing weights require more powerful equipment leading to an increase in operational time and consequently an increase in cost. Larger and more appropriate drilling rigs should be used if the wells are to be deviated.

A vertical well is recommended over a deviated. The vertical option will, most likely, require additional wells to be drilled in order to achieve the same flowrates as deviated wells would achieve. However, vertical wells are associated with less risk and lower cost.

Time and cost estimates were prepared by Awell for three scenarios from reservoir simulations, reflecting the time used to drill and complete a vertical well to the desired depths. A span of several wells drilled in one continuous campaign can be expected to have a positive effect on the well cost due to learning and constantly obtaining better knowledge about the given circumstances during the operation. The cost reflects a decrease in the optimization with the highest potential in the beginning.

## 6 Geotechnics and geology section, DTU

DTU was to provide information regarding the mechanical properties of the limestone in order to reduce the well drilling risks and maximize the well productivity.

The few deep wells in Denmark provide little geotechnical information. The Dan field located in the North Sea, where both geotechnical and geophysical data are available, was considered as a possible analogue for the chalk group in Zealand. Based on burial anomaly studies the effective stress of the Dan field and the greater Copenhagen area are considered to be the same. The two are, however, distinctly different when it comes to Porosity – E-modulus relationship due to different temperature history, making the Dan field an unfit analogue for the Copenhagen area.

DTU's results are therefore that deep chalk cores from the Copenhagen area are needed to provide material for pertinent geotechnical testing. Furthermore, it is advised to study the effect of water injection on the geotechnical properties.

# 7 Establishing thermal storage in the chalk/limestone aquifer, GEUS

The chalk in the storage zone is generally characterized by very high porosity and low matrix permeability. The presence of natural fractures in the chalk means that the effective permeability is somewhat higher than the matrix permeability, depending on the fracture intensity. The GEUS work on evaluating the storage potential is based primarily on the existing knowledge of the subsurface, including data available from wells, core material, logs, seismic data and literature on geological aspects of the chalk.

The chalk section is subdivided into a number of flow units that differ in terms of geological character and reservoir properties. In order to pinpoint a series of localities suitable for thermal storage in the chalk section, GEUS characterised each flow unit with respect to the distribution of porosity, permeability, temperature and thermal properties. The work resulted in a geological model that forms the basis for the subsequent reservoir simulations. The unit having the most favourable reservoir properties is the Lower Maastrichtian Hvidskud succession. This depth to the top of this unit is about 600 metres, but the depth varies across the study area due to basin character and post-depositional movements and erosion.

GEUS conducted a number of reservoir simulations aiming at estimating volumes, potential production and injection rates together with an expected pressure and temperature development.

The well configuration includes two vertical wells with a distance of 1 km between. The presumed charging period is May-mid October. Formation water is extracted from HTES-1 (cold well) and heated up to 90% by means of excess heat and injection into the HTES-2 (warm well). The presumed extracting period is November–mid-April. The energy is extracted using a heat exchanger that heats the circulating water of the district heating system.

Conceptual model and prognosis for the Vestforbrænding site:

In the base case simulations, GEUS consider unstimulated wells drilled into the presumed storage reservoir in the chalk. The base case simulations point the following flow rates:

- Average injection rate: 25 m3/hr
- Average production rate: 35 m3/hr

Higher flow rates can be achieved by using well stimulation techniques.

The Vestforbrænding site is considered a high-risk potential, as the matrix permeability is low and the effective permeability is not known. Further evaluation is therefore recommended prior to drilling.

A conceptual model for presumed faulted/fractures sites:

The prospects are associated with areas affected by intensive faulting, creating fractures in the chalk, the Amager, Carlsberg, and Øresund fault systems. The Carlsberg fault zone is especially associated with a general increase in permeability and hydraulic conductivity, making the zone, in GEUS's opinion, especially relevant when considering thermal storage. However, there is a potential risk of 'loosing' the injected water, as the hot water may migrate into the fault zone.

All sites related to highly faulted zones are considered to be high-risk prospects as the degree of fracturing is difficult to address, meaning that the effective permeability estimates are very uncertain. Drilling, testing and coring might, therefore, be the only practical way to test and evaluate the prospect.

# 8 Business Case Models, Ross

Numerical models of reservoir flow and heat transport were constructed and run to generate 30-year heat energy production profiles. The models were developed to: Quantify the range of production rates for a single well completed in a chalk reservoir, quantify the range of recovery efficiency of wells injecting and back-producing hot water, and generate a range of thermal energy production profiles for use in the business case models.

The models for the low case, best-technical estimate, and high case were used for optimizing screen lengths and production rates of the wells and estimating thermal production per well.

<u>Business case models:</u>

The business case models were calculated using a cash flow model with the following input:

- 30-year thermal energy production profiles
- Well design, count, drilling, construction and cost
- Design and cost of facilities
- Financing
- Operating cost of facilities and wells

The business case models were run with a target flows of 20–150 m3/h, and 50 m3/h is considered the best technical estimate. The single well simulation was used to determine the number of wells needed and the well count then used for determining the cost of well construction and operation.

The thermal energy production profile used to define revenue in the business case models was calculated using energy production profiles from a single well.

Capital expenditure (CAPEX) for the project includes the money spent on the front-end engineering design, the well design and construction, the surface plant design and construction and host modifications. The annual cost of financing capital expenditures was calculated assuming a 6% loan over 30 years.

Operating expenses (OPEX) were calculated based on estimates on the electricity demands, electricity cost and the cost of maintenance and remedial treatments.

Cash flow models generated showed that the high case and best-technical estimate 90°C models all returned a positive cash flow over a 30-year period, whereas the low case and best-technical estimate 80°C models had a negative or only a slightly positive cash flow after a 30-year production.

# 9 Conclusive remarks

The project team has analyzed all existing data material, but a number of crucial reservoir parameters cannot be fully determined for the time being. It is, however, the project group's assessment that large-scale seasonal heat storage in the chalk section can be feasible despite of low permeability. To compensate for the low permeability, application of well stimulation and drilling of several production and injection wells should be considered. The project team recommends drilling a pilot well prior to establishing a storage plant; the pilot well should be flow tested, cored and logged. The first activity could be flow testing the pilot well in order to evaluate the productivity of the chalk in the target zone.

The existing knowledge on the reservoir parameters of the chalk in the storage zone is thus limited. The project group recommends, therefore, acquiring supplementary data during a Phase-2 working period.

# Appendices

# 1 Scope

Outline of the component set-up that makes up the surface plant for a heat storage facility.

# 2 The surface plant

The results of the pump test in the first production well, serves as a good preliminary basis for design of the surface plant. However, the final design can only be determined when the pump test of all wells has been carried out.
The surface plant extracts the heat from the reservoir via the production well and transfer the heat to the district heating grid in the most efficient and economical way, then pump the cooled formation water back into the reservoir through the injection well.

# 3 Different concepts for the surface plant

The design of the surface plant must be highly adapted to current values for flow, temperature, data from the reservoir and district heating system, but in addition, a series of conceptual choices will be taken early in the process, as described below.

When the reservoir is fully charged the temperature is the highest. If the reservoir temperature is significantly higher than the return temperature of the district heating system, the energy can in principle be transferred to the district heating grid only by direct heat exchange. However, it would be advantageous to transfer more heat using a heat pump as it provides a much better utilization of the resource. At reservoir temperatures, which are at or below the district heating grid temperature it will be necessary to supplement the temperature with afterheat, or with the utilization of a heat pump.

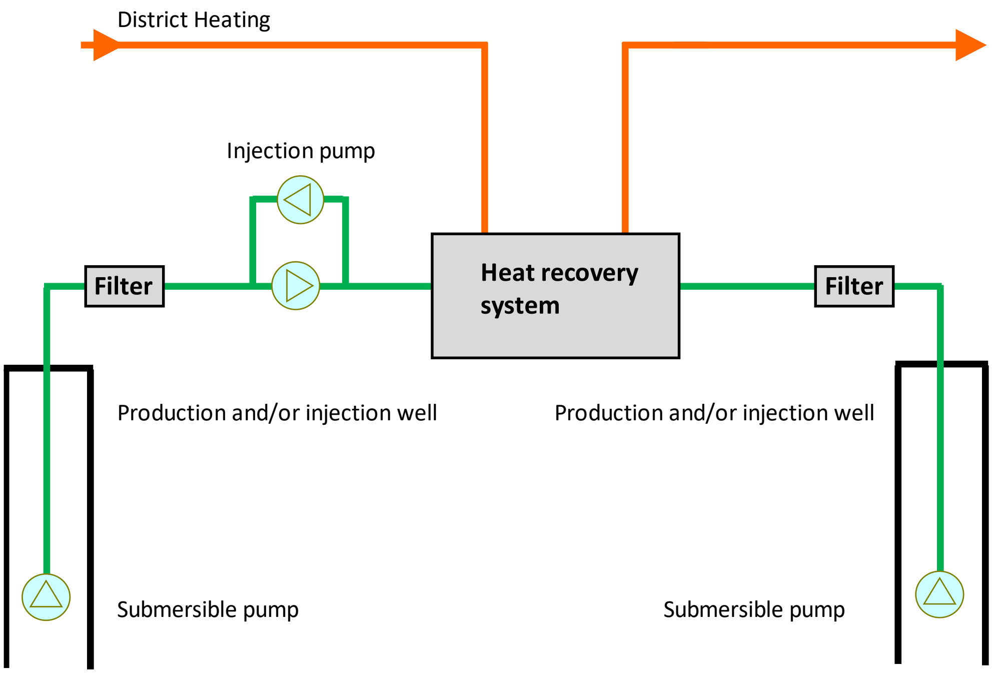



*Figure 1 Surface plant with its essential parts*

The overall design in figure 1 is built around a district heating circuit (orange) and water from the formation (green). Often the surface plant is more complicated with more parallel and / or series-connected heat exchangers and heat pumps. It is possible to increase the capacity of the wells with the utilization of heat pumps. Filters are used to filter any particles that may be led up by the well together with the water before the water from the formation is passed through the heat exchanger(s) and the subsequent heat pump where the energy is transferred to the district heating grid. After heat exchanger and / or heat pump, a further, finer (deep) filtration is performed before the water is injected back into the reservoir, possibly using an injection pump.
Depending on the return temperature of the district heating water, it should be possible to cool the water from the formation to around 20-10C. Here by it is possible to extend the capacity with 75% (from 80C-40C to 80C-10C) with the same flowrate from the wells.

## 3.1 Electric submersible pump (ESP)

In the production well, a submersible pump is installed, which will pump the water from the formation to the surface and circulate it in the surface plant. It is important that the pressure is kept above the bubble point of dissolved gases in the formation water.

The ESP is immersed in the production well below the water table. If the boreholes are bent, it is important that the curvature is not too high, as it may be difficult or impossible to install the pump. The depth of the pump depends on a number of parameters such as the partial pressure of the dissolved gases, the pressure in the reservoir and the lowering of the water level when operating the pump. Therefore, the installation depth of the pump must be adapted to local conditions.
The pump is powered electrically and supplied from a frequency converter (VSD) via a high-voltage cable that connects the pump and is installed with it.

The submersible pump is a very critical component in the operation of the plant. At the same time, the pump is a special component, for which there is typically a long delivery time. As part of the spare part strategy, it should therefore be considered to have a replacement submersible pump in stock.

## 3.2 Filters

A good reservoir is characterized by high porosity and moderate or poor cementation, there may be impurities in the produced salt water in the form of particles and corrosion products from the production well and the surface plant. These impurities will settle in the system and especially in the injection well and reservoir unless removed in the surface plant.
It is therefore necessary to install filters which are normally installed both immediately after the production well and just before the injection well. The first filters must ensure that particles larger than, for example, 2 microns are filtered off before the water flows into heat exchangers and / or heat pumps. This filtering is typically done with bag filters and possibly mechanical self-cleaning filters.

## 3.3 Heat recovery system

The heat recovery system is made of different components which can be either passive (heat exchanger) or active (heat pump).

## 3.4 Heat exchangers

It is advantageous to use a heat exchanger early in the process if the reservoir temperature is higher than the return temperature of the district heating water.

The salt content of the water (salinity) makes it potentially highly corrosive if it comes into contact with oxygen, and therefore the plates of heat exchangers should be made of titanium.

## 3.5 Heat pump

In essence a refrigeration system/ heat pump moves energy in the form of temperature from a cold sink to a heat sink. It is possible to drive the process by the means of either heat or mechanical energy.

## 3.6 Injection pump (HPS)

Unless the reservoir's overall water conducting properties are very good, it is necessary to install an injection pump to push the cooled water back into the reservoir. The injection pump can typically deliver pressure equivalent to the maximum pressure for the wellhead.
The injection pump motor is supplied electrically via a frequency converter (VSD).

## 3.7 Pipes, valves and instruments

Due to the salinity of the water from the formation it is necessary to reduce the pipes and instruments from oxygen exposure.
To counteract corrosion, typically nitrogen ($N_2$) is added to the surface plant and wells when the plant is stopped. Pipes, valves and instruments are also dimensioned with a larger corrosion surcharge.

## 3.8 Industrial control system (ICS)

Is used for industrial process control, and a computer is used to access different instruments and valves.

## 3.9 Plant constellation CAPEX

Total capital expenditure (CAPEX) of the surface plant is shown in the following graphs. The main difference is the heat pump technology.

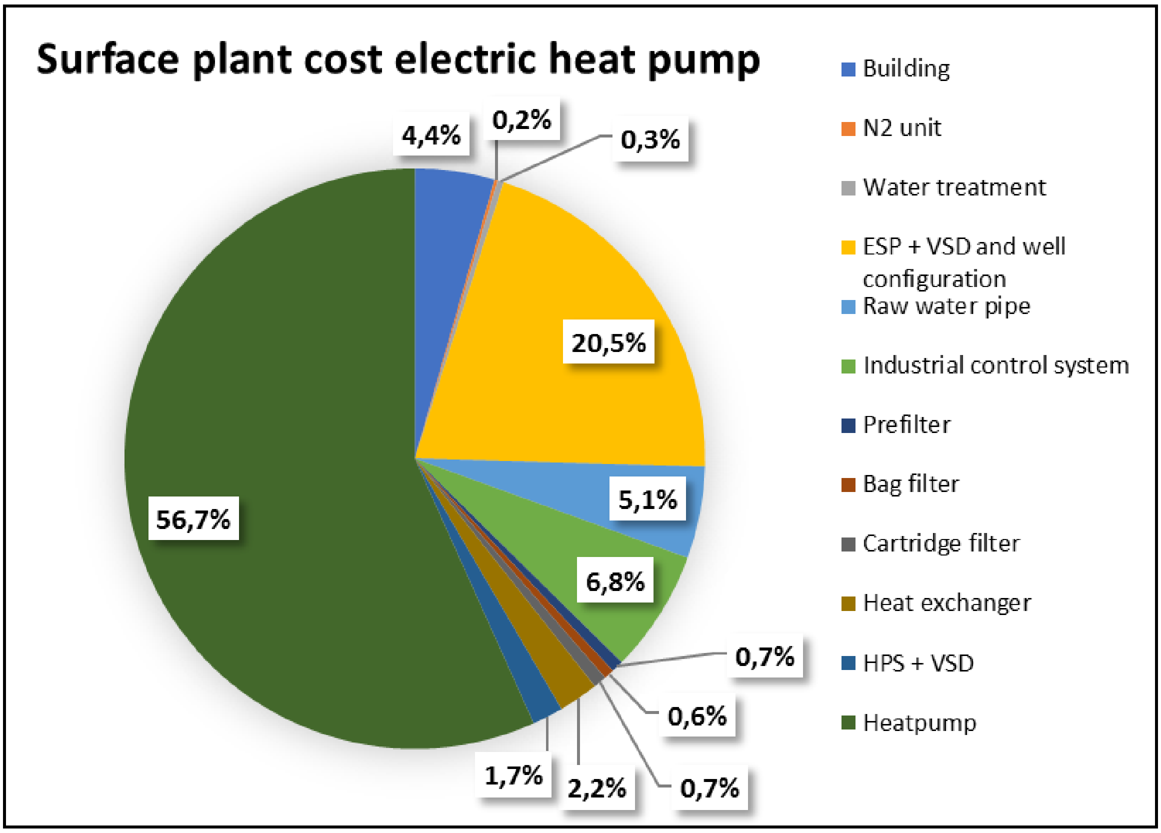



*Figure 2 Total cost 29,3 mio. Kr.*

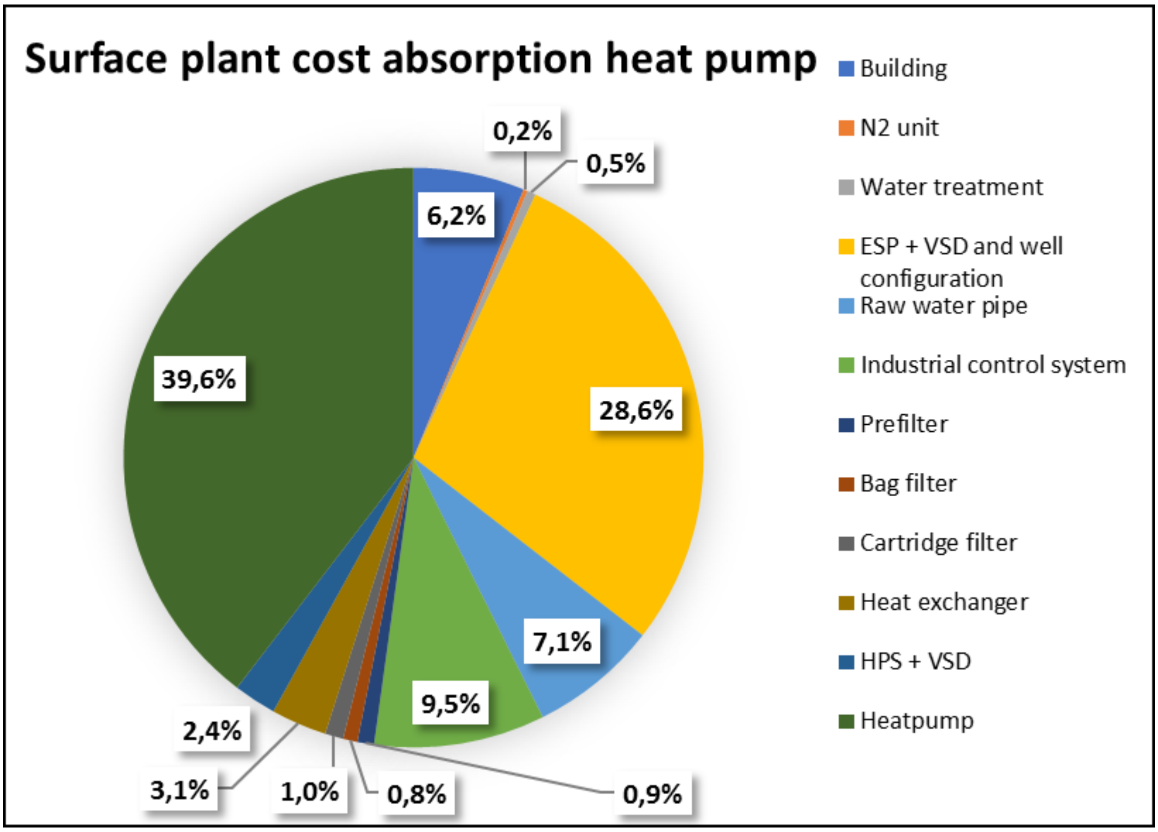



*Figure 3 Total cost 21 mio. Kr.*

# 4 Vapor absorption system (absorption heat pump - AHP)

Access to process heat is required to drive the absorption heat pump and will therefore not be as flexible as electric driven compressor heat pumps when it comes to the location of the surface plant. Process heat will be an economically attractive choice compared to the high cost of electricity/mechanical energy, and the difference will be quantified in the following.
In a scenario where steam is extracted at 170°C, the absorption heat pump should be able to deliver district heating at high temperatures to the transmission grid. At 140°C the absorption heat pump can deliver district heating temperatures at 80°C to the distribution grid.

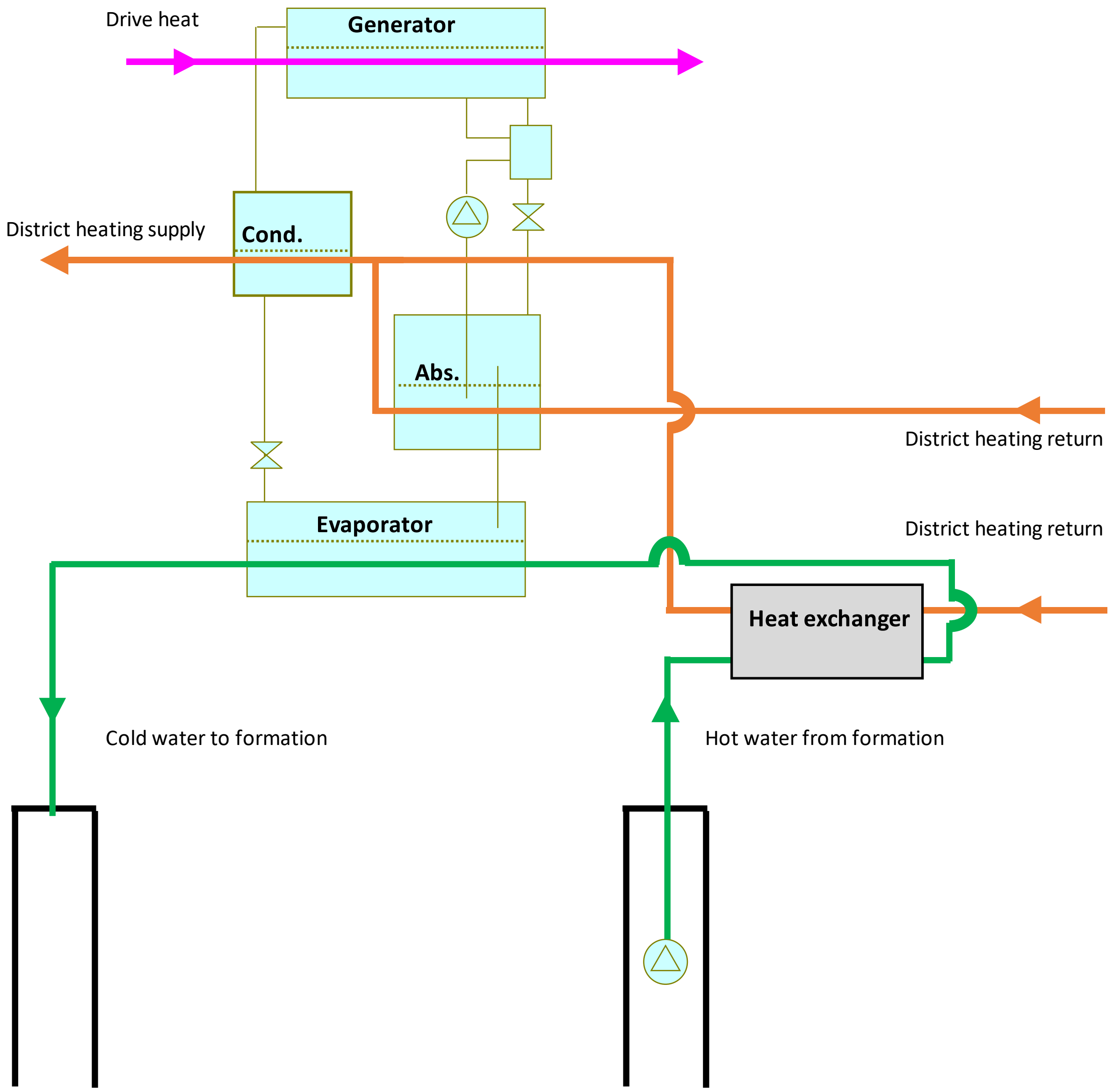
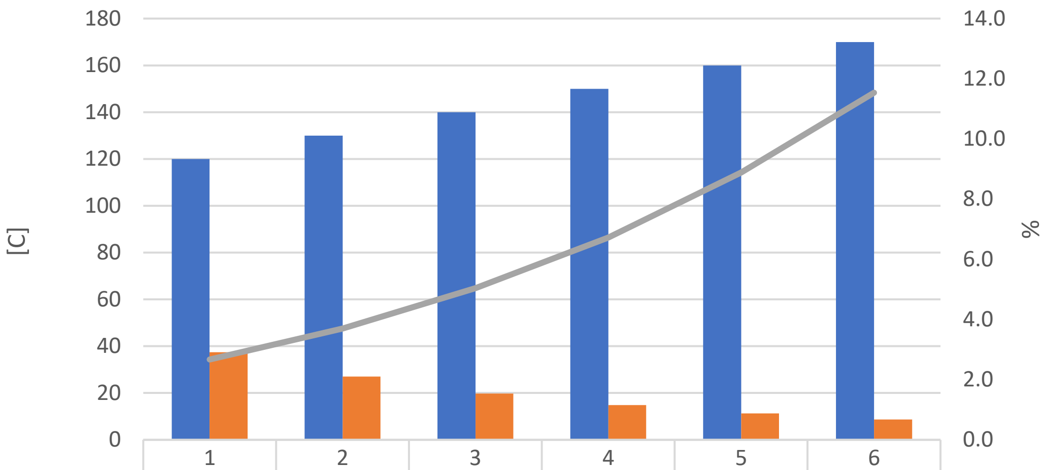



*Figure 4 surface plant with absorption heat pump*

In the case where the surface plant is constructed close to a combined heat and power station (CHP), it will be possible to increase the temperature of the steam, so it will be sufficient to drive the absorption heat pump.

With basis in the turbine, one most note that the steam pressure inlet is a constant, but it is possible to change the condensation pressure after the turbine. Depending on the existing turbine it may be necessary to make a steam bypass to extract the steam at the right temperature. There comes a penalty for extraction high temperature steam in the form of a loss in electric power, which is highlighted in the graph below.




| | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|
| Steam out [C] | 120 | 130 | 140 | 150 | 160 | 170 |
| COP | 37.5 | 27.1 | 19.8 | 14.9 | 11.3 | 8.7 |
| fuel increase [%] | 2.7 | 3.7 | 5.0 | 6.7 | 8.9 | 11.5 |

*Figure 5 Fuel increase and COP decrease as a function of steam temperature extraction*

The data on the graph is based on an inlet pressure of 55 Bar(a) to the turbine.

The "COP" in this scenario is the decrease in electric power compared to the thermal energy from steam condensation.
To compensate for the loss in electric power, fuel consumption will increase but moderate (up to 11,5%) if the CHP plant is a waste incineration plant, this will have little influence on OPEX.

The drive heat to the generator will define the temperature in the condensator, like wise will the temperature in the absorber define the temperature in the evaporator. If the district heating return temperature is 40C it should be possible to cool the water from the formation to 10C. The temperature in the reservoir will be depleted as a function of time, and the absorption heat pump will compensate for this, by increasing the evaporation capacity. The relationship between the generator and the evaporator is about 1:0,7 (generator: evaporator), therefore the generator will also increase as shown in the graph below:

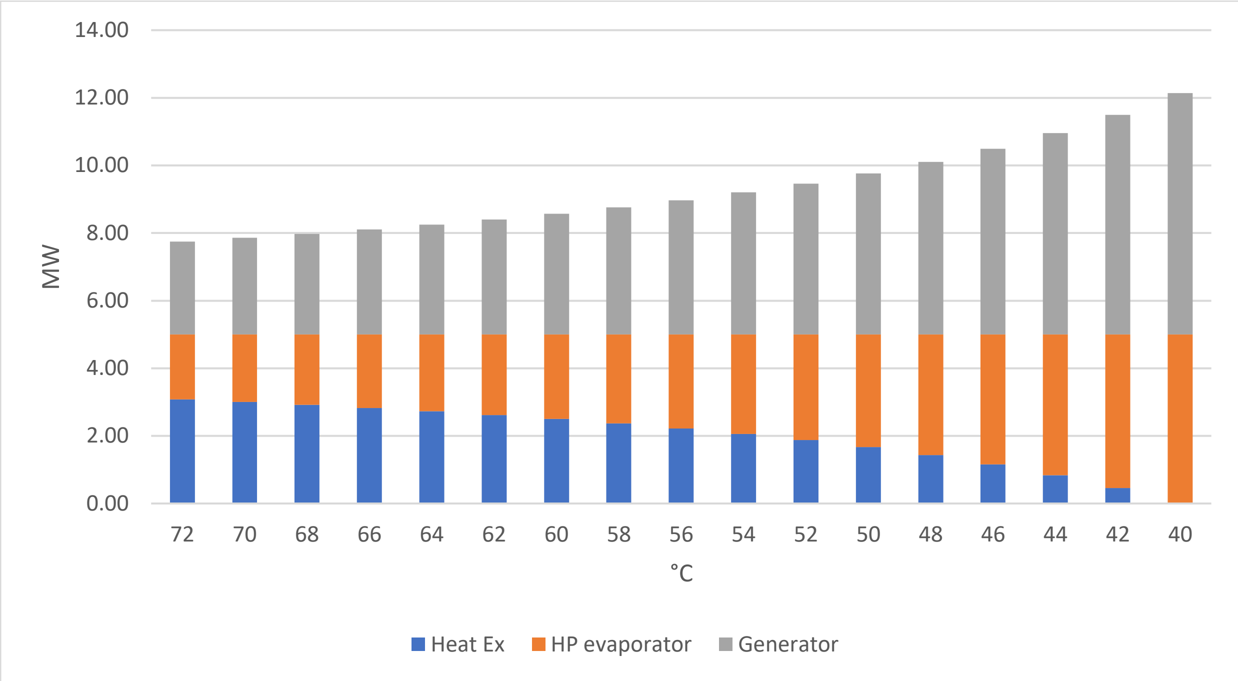



*Figure 6 - Heat exchanger and heat pump (HP) power as a function of reservoir temperature. The reservoir temperature is dependent of the local geology.*

As the temperature in the reservoir decreases the energy from the heat exchanger will decline, and the absorption heat pump will increase its share of the total power delivered to the grid. At reservoir temperature = 48°C the drive heat and the recovered heat from the reservoir will be equal. At 40 °C the reservoir temperature is equal to district heating return and the heat exchanger is unable to deliver heat to the system.

## 5 Vapor compression system (electric heat pump - EHP)

An electric heat pump has a higher degree of flexibility and can be built far away from the plant. The COP (coefficient of performance) is also higher compared to the absorption heat pump, but is sensitive to high condensation temperatures.

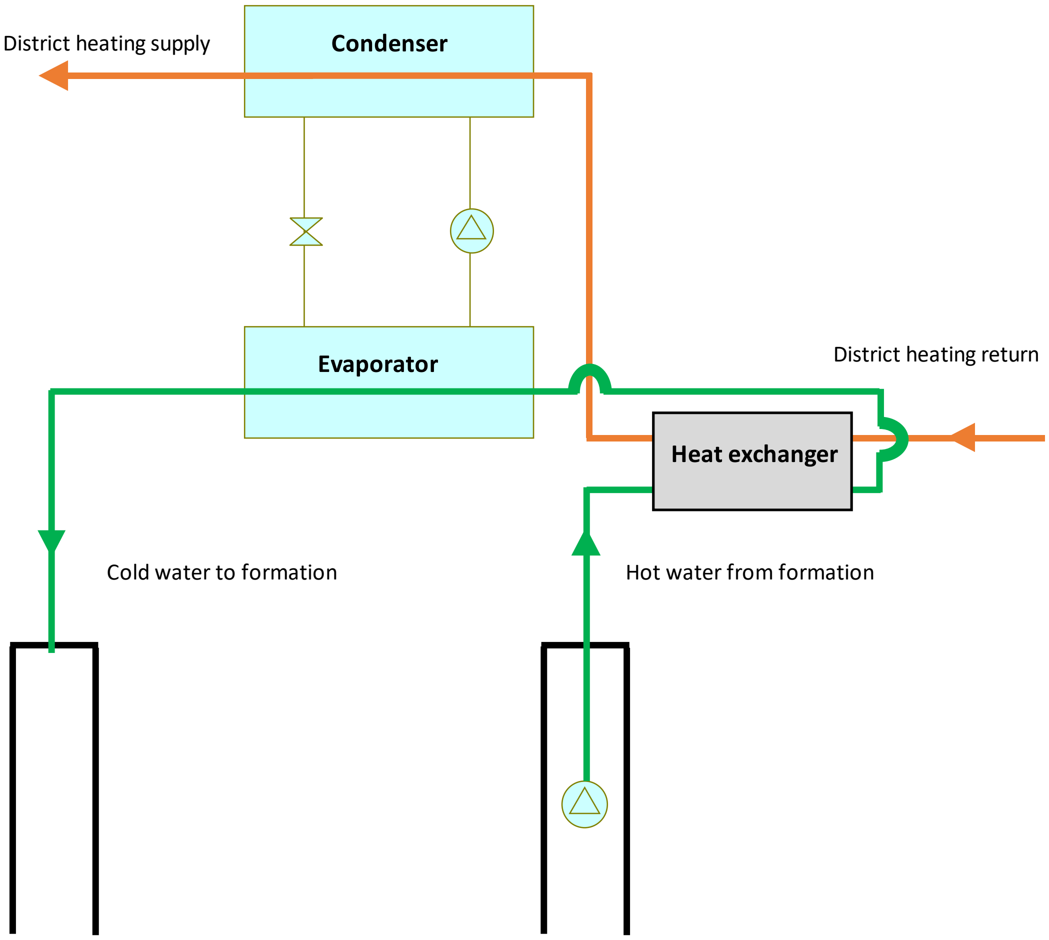



*Figure 7 Surface plant with EHP*

It is possible to extract the majority of the heat using the heat exchanger but as time progresses the temperature will drop. This is illustrated in the following graph:

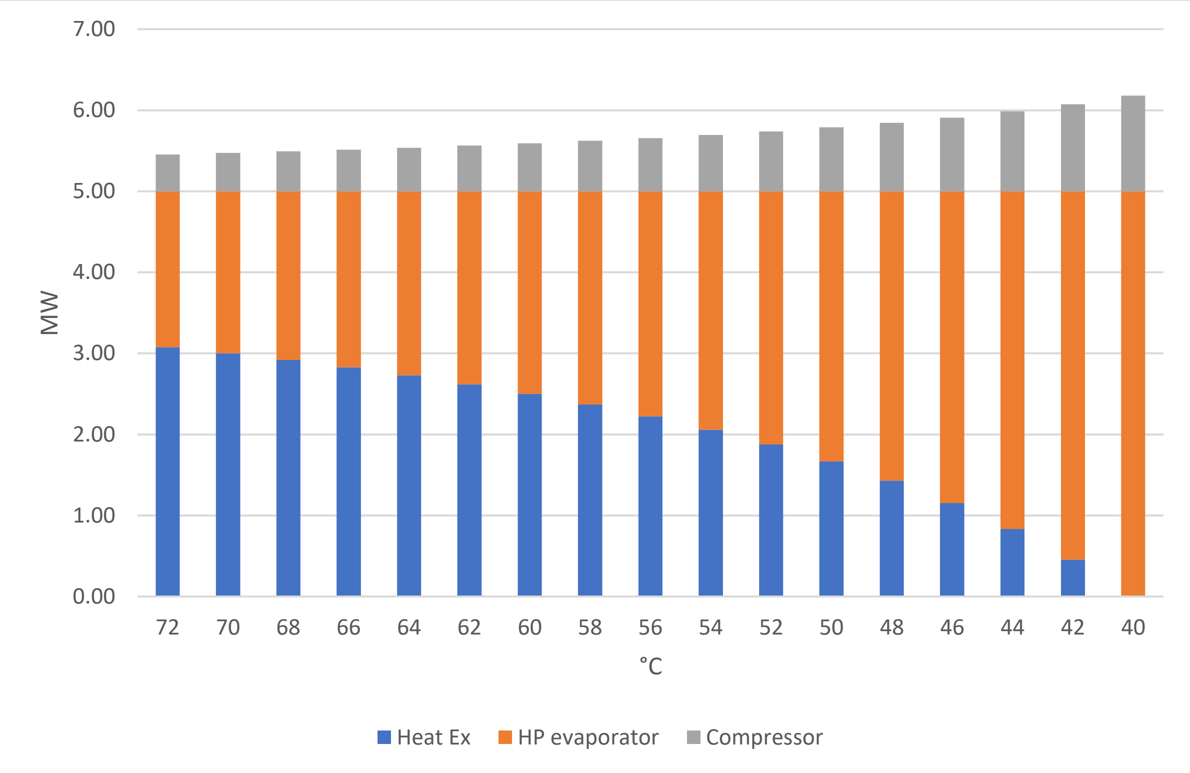



*Figure 8 Different energy systems contribution to the energy output as a function of reservoir temperature. The heat pump will cool the water from the formation to 20C before returning it.*

Heat from the reservoir will be extracted directly from the heat exchanger, but as time progresses the temperature will decrease, and the heat pump will contribute more to the total heat output. The compressor will also add additional heat to the system, but to make sure the system is in thermal equilibrium, the compressor energy will be added to the stored energy.

It is important to remember that the flow is not a constant, and will increase with the decrease in reservoir temperature. When the reservoir is fully charged the temperature difference will be 72°C-20°C (20°C is the temperature after the heat pump). The difference between the starting flow and the flow close to the end of the discharge period will be a factor of 2,6.

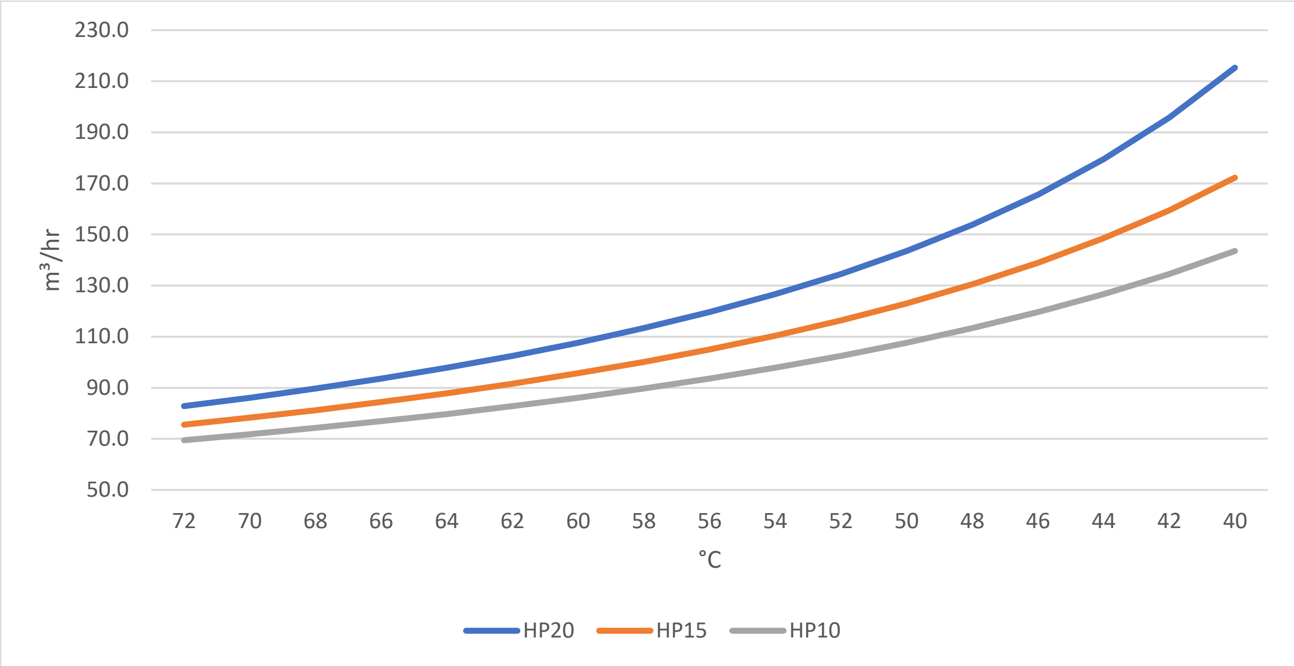



*Figure 9 flow from the formation as a function of reservoir temperature. HP20 cools the water from the formation to 20C, whereas HP10 cools the water to 10C.*

One should note looking at Figure 9 that the increased flow requires additional energy for the pumps. A pump follows the affinity laws which states that the flow is proportional to the shaft speed, but the power is proportional to the shaft speed cubed. Hence the power consumption of the pumps in the end of the discharge cycle is higher than the beginning.

The amount of energy required to drive the heat pump at different evaporation temperatures is illustrated in the following graph

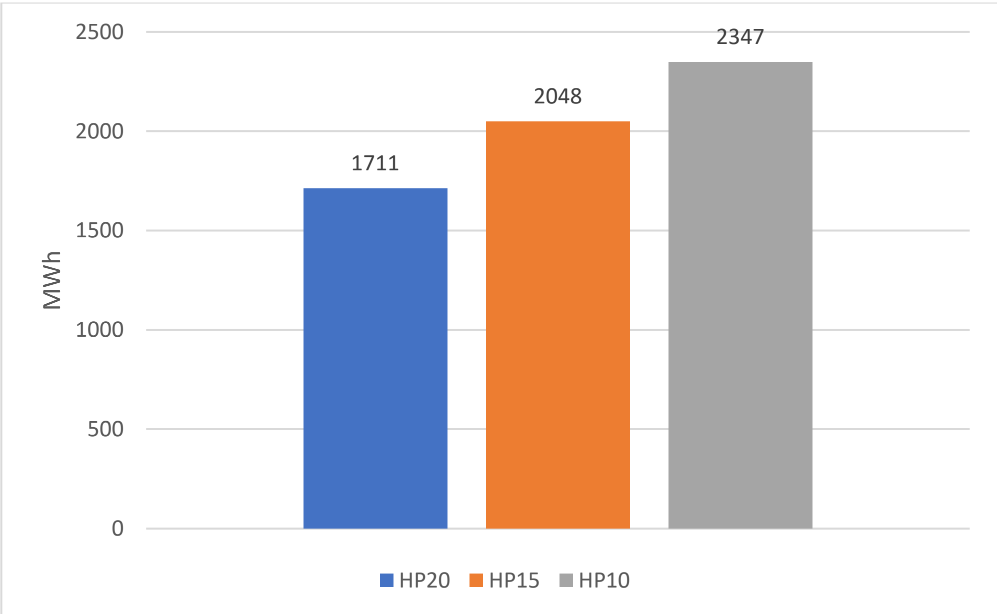



*Figure 10 Energy required to drive the heat pump at different evaporation temperatures. HP20 = evaporator temperature of 20C.*

When the heat pump is working at an evaporation temperature of 10C, it will require more energy compared to an evaporation temperature of 20C, but the flow will be 17%-60% lower.
The injection pressure is also critical for the energy consumption of pump, and hence the temperature of the recirculated water to the formation. With low temperatures the viscosity of the fluid will increase and increase the injection pressure. It is not known how big an effect this will have on the injection well.

# 6 Cost and energy optimization

In Figure 2 & Figure 3 of the report an overview of the cost of the components for the surface plant was highlighted. It is clear that the heat pump by far is the biggest expense in the surface plant, and a reduction in the size of the heat pump will lead to savings in the cost of the surface plant. One way is to heat the storage to at temperature higher than the natural temperature in the formation. This will require more heat being transferred to the reservoir in summer and less heat extracted initially. From the following graph, the relationship between variable heat price and the reservoir temperature is highlighted:

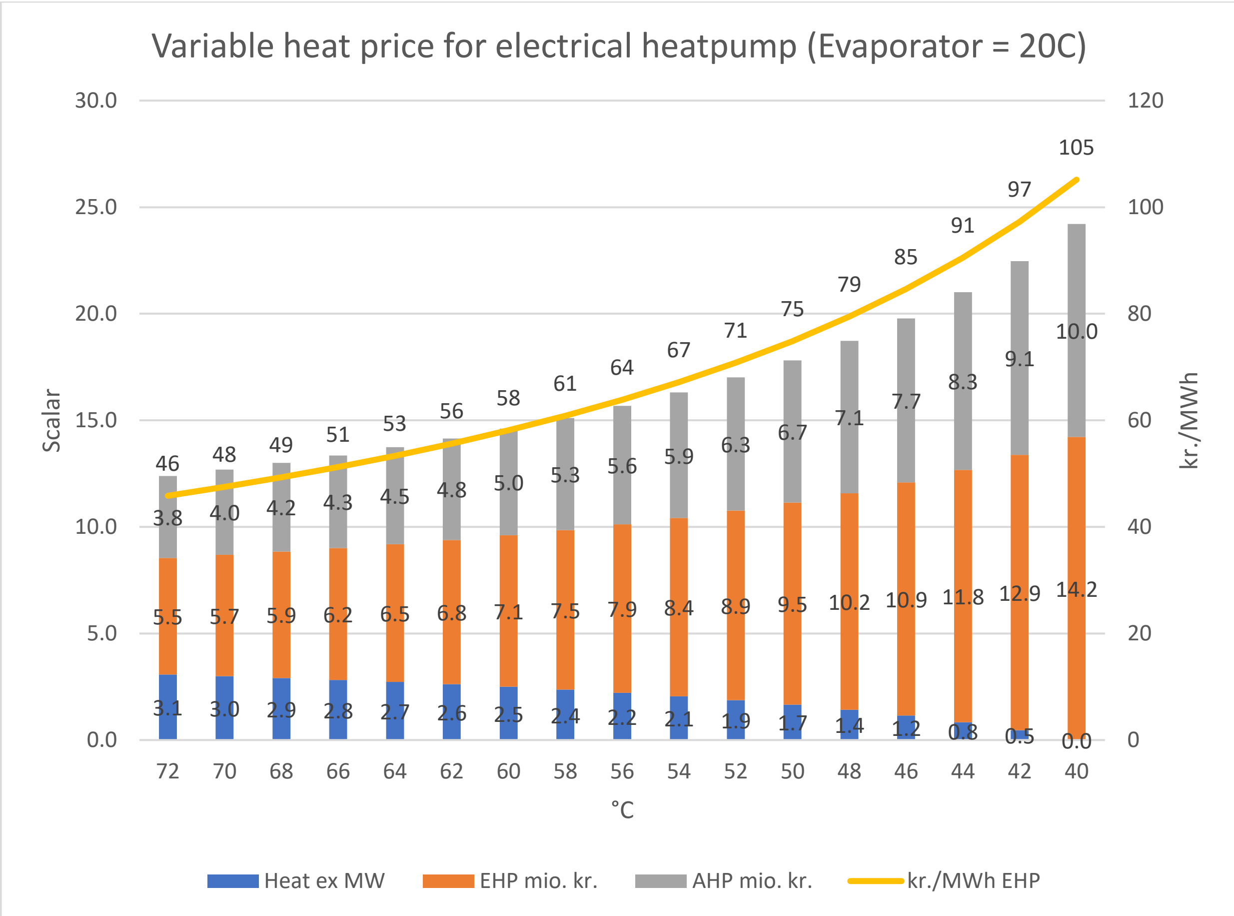



*Figure 11 decline in reservoir temperature will decrease the output from the heat exchanger. The heat pump will compensate for this, but the capacity will have to increase and the cost will rise as a result.*

From the graph above the reference temperature in the reservoir is 40°C and is equivalent to the return temperature form the district heating grid. In this scenario an electric heat pump will cost 14,2 mio. kr. and deliver 6,18MW heat at 80C to the district heating grid. At a fixed price of electricity at 550 kr./MWh the heat price will be equal to 105 kr./MWh.
The absorption heatpump can be acquired cheaper but the cost of drive heat is location specific and can range from cost neutral to more expensive than electricity. One most note that the y-axis to the left is a scalar, meaning that at reservoir temperature at 72C the heat exchanger is 3,1 MW and a EHP will cost 5,5 mio. kr. and an AHP will cost 3,8 mio. kr.

If excess heat is transferred to the reservoir it is possible to change the reference temperature to 50°C, in doing so, the cost of the surface plant will decrease as well as the variable heat price amounting to:

Cost saving for the heat pump: 29%

Reduction in variable heat price for the EHP: 29%

One should note that the heat exchanger is a passive system which do not require any energy to operate and the investment is 15-22 times lower compared to the heat pump. To reduce cost, it is necessary for the heat exchanger to transfer as much heat as possible.

OE3i ApS
Hestehaven 21A
5260 Odense

# EUDP 16-I (j.no. 64016-0014)
# Project Report
## WP2
## Data and Model Simulation of Storage Potential

## 1 Description

The primary goal of this part of WP2 was to clarify the economic potential of large thermal underground storages and to estimate how much the heat producer's bottom line can be improved. A number of close-to-real-world-scenarios were defined and various simulations for each were calculated by the schedule optimization software Mentor Planner for the period April 1st 2016 to March 31st 2017. Mentor Planner calculates the best possible operation schedules for a power and / or heat producing plants, taking into account:

- Costs for producing energy (power and / or heat)
- Prices for selling power, which vary from hour to hour
- Prices for selling heat, which are adjusted on a quarterly or yearly basis
- Heat demand in the heating grid(s)
- Level of heat energy in the thermal storage
- Thermal storage capacity
- Heat loss in the thermal storage
- Maximum heat effect that can be transferred to and from the thermal storage

The simulations were performed with variations for:

- Thermal storage capacity
- Heat loss in the thermal storage
- Maximum heat effect that can be transferred to and from the thermal storage

## 2 Data Acquisition

For the simulations there are a few requirements to be considered. The heat demand has to be known or it has to be predicted. Prices for selling power have to be known and costs for producing energy as well as other properties of the heating grid and the heating plant have to be configured.

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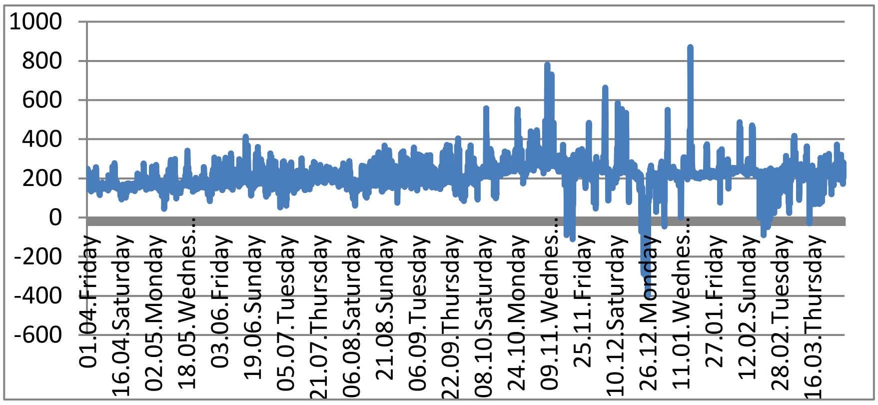
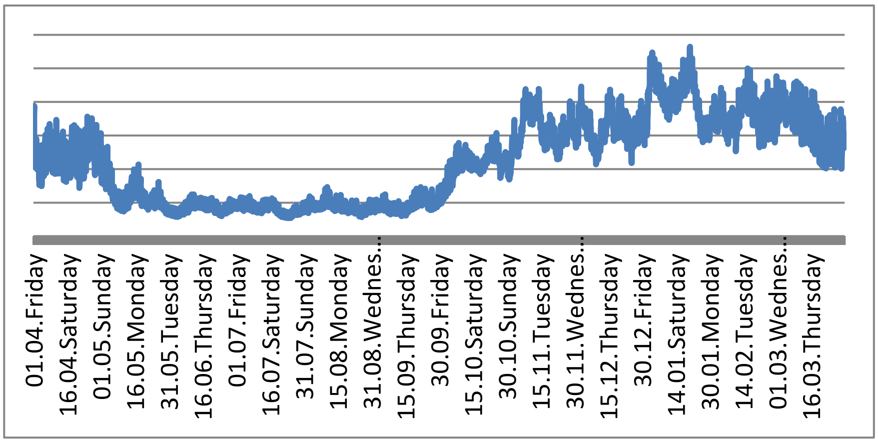
Hestehaven 21A
5260 Odense

It was planned to contact existing customers and request permission to use installed setups and historical data. It turned out, however, that the customers are not particularly willing to release these data, in order not to allow competitors to gain insight into their business. For this reason, we decided to configure several types of plants with averaged data of multiple real world installations.

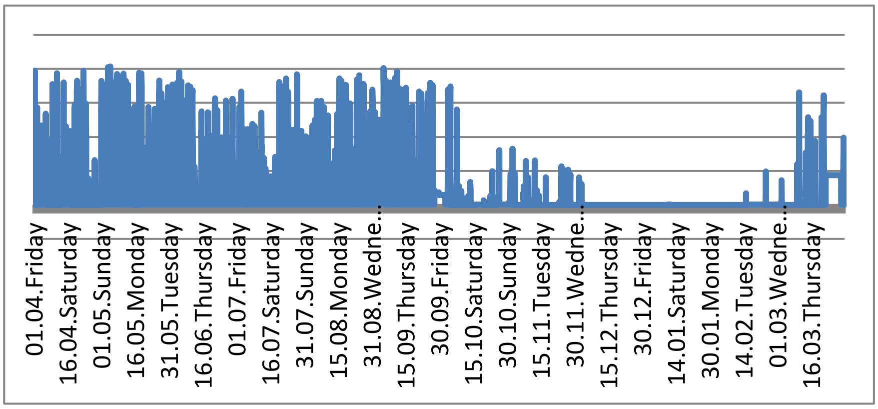
The prices for selling power were taken from the price area DK2 and which are valid for the eastern part of Denmark (Zealand and Lolland Falster).




The heat demand was calculated as average from four different installations, each with their own hourly heat profile. In the simulations the averaged heat demand was scaled to fit the size of the production units.




Heat production from solar panels was calculated based on historical weather data. The historical weather data were averaged from three different locations. In the simulations, the heat production from solar panels was scaled to simulate different sizes of solar heating plants.



For the energy producing units we assumed operation loads points which were taken from typical installations of that unit type. Both the production values and cost parameters were calculated as simple average.

# 3 Test Scenarios Setup

It was planned to perform simulations with many different types of production units. However, it turned out very early in the process, that it makes most sense to work with units that can produce fairly cheap excess heat during the summer, save the heat for winter usage and thereby replace heat production from relatively expansive peak units. The investigations within this work package were concentrated on three major types of production units:

- Incineration plant
    - Production costs and load point values are averaged from multiple existing installations
    - Heat demand is averaged from four different installations
    - Prices for selling power are taken from the DK2 area in Denmark
    - Minimum backpressure 3 $MW_{el}$ / 6 $MW_{th}$
    - Maximum backpressure 16 $MW_{el}$ / 42 $MW_{th}$
    - Bypass 2 $MW_{el}$ / 54 $MW_{th}$
    - Supplied by a gas boiler 1 - 100 MW operating at 700 DKK / $MWh_{th}$
- Solar heating plant
    - Production costs are assumed to be 0
    - Heat demand is averaged from four different installations
    - Solar panel area: small, medium, large
    - Supplied by a gas boiler 1 - 100 MW operating at 700 DKK / $MWh_{th}$
- Wood chips plant
    - Production costs are assumed to be low but no real installation exists
    - Heat demand is averaged from four different installations
    - Prices for selling power are taken from the DK2 area in Denmark
    - Minimum backpressure 1 $MW_{el}$ / 12 $MW_{th}$
    - Maximum backpressure 3,5 $MW_{el}$ / 27,5 $MW_{th}$
    - Supplied by a gas boiler 1 - 100 MW operating at 700 DKK / $MWh_{th}$

# 4 Simulations

All simulations are calculated for the period April 1$^{st}$ 2016 to March 31$^{st}$ 2017.

The total economic profit for each simulation was calculated based on the calculated optimal operation schedules. Results of the different simulations were analysed and compared. Especially the comparisons of simulations for different sizes of the thermal storage, while keeping other variables constant, are of great interest. Although the heat loss in the thermal storage plays a certain role, the analyses have shown that the maximum heat effect that can be transferred to and from the storage is most important.

It would be desirable if one coherent operation schedule could be calculated for the entire simulation period by one single call to the optimization software, however this is currently not possible due to the number of involved variables and data.

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Hestehaven 21A
5260 Odense

Instead the simulation process was separated into smaller steps. In each optimization step a period of 2 month was calculated. The schedules for the first month of each calculation were taken into a result data set and the start conditions for the next optimization (especially energy level of thermal storage) were set to the data which were calculated for the time at the end of the first month.

Example:

- First optimization: Optimize April 1st to May 31st, keep April trash May
- Second optimization: Optimize May 1st to June 30st, keep May trash June
- Third optimization: Optimize June 1st to July 31st, keep June trash July

## 4.1 Incineration plant

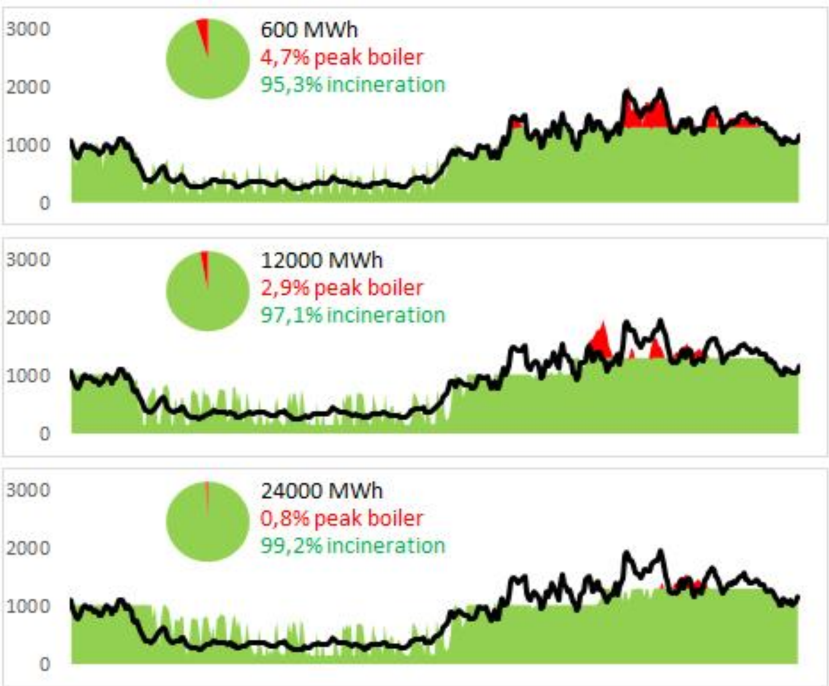
Incineration plants normally produce at very low cost. The main reason is the low price for the waste that is burned, which very often is negative. Negative prices mean that the plant is getting paid for burning waste. For this reason, many incinerations produce excess heat during the summer season which then has to be cooled down for some cost.

Comparing simulations with different sizes of the thermal storage shows that there is a direct correlation between the size of the thermal storage and the economic output. Large thermal storages make it possible to produce and save heat during the summer at relatively low cost. Operations of peak boilers in the winter, which normally are quite expensive, are thereby reduced. On the other hand, the thermal storage should not be larger than the amount of heat that normally is produced by the peak boilers; otherwise the capacity of the heat storage would not be fully utilized.

With a thermal storage of 12.000 MWh, we found an annual increase of the profit of around 6.000.000 DKK compared to a thermal storage of 600 MWh.

A thermal storage of 24.000 MWh can result in 12.000.000 DKK more profit compared to a 600 MWh storage.

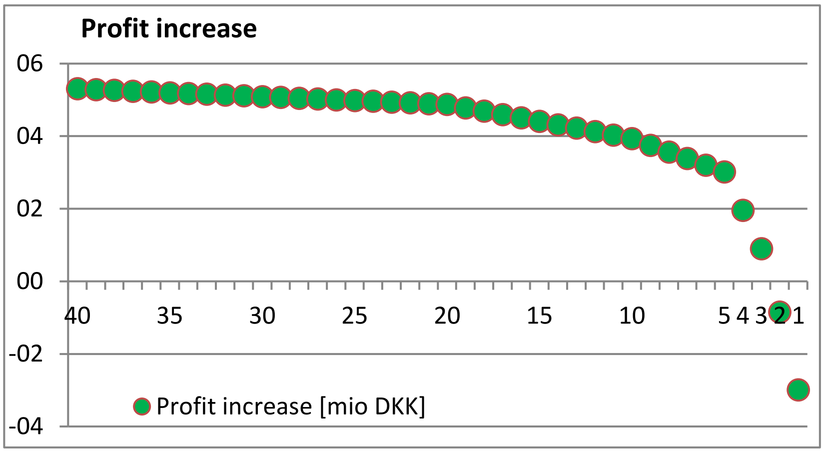
It should be mentioned that these results are achieved if neither heat loss in the heat storage nor the maximum transfer rate to and from the storage is included in the calculations.



CHPs (combined heat and power) are typically producing power and heat in combination. These units most often operate on either the backpressure line (more fuel means more heat and more power) or the bypass line (more bypass means more heat but less power). It is preferable to produce power at hours with highest prices without overfilling or emptying the heat storage at the same time. Changes of the power prices can be significant enough to change the operation mode. The amount of heat that is produced at the same time can also change dramatically within short time. For the economic performance, it is crucial that the excess heat that is not consumed immediately in the heating grid can be saved into the thermal storage.

A large number of simulations have been done to show the importance of the transfer rate to and from the thermal storage.

The diagram to the right shows the maximum transfer rate on the x-axis and the increase in the profit that a 12.000 MWh HTES generates compared to a 600 MWh traditional storage on the y-axis.



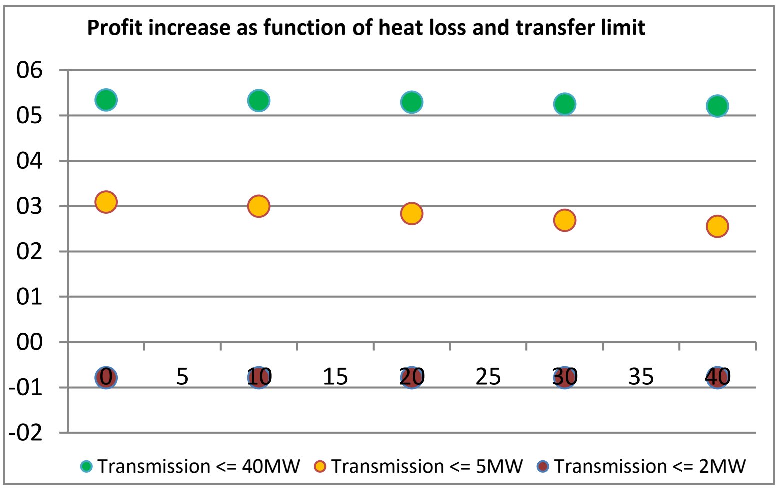

As expected, the increase in the profit is reduced, as the transfer rate decreases.

With a maximum transfer rate of 20 MW or higher the test incineration performs very well and transfer rates between 5 and 20 MW are still ok. The slight decline of the profit increase is due to the fact that the periods for high power prices can no longer be fully utilized. At transfer rates under 5 MW, the heat storage cannot be discharged fast enough in the winter, leading to increased usage of peak boilers and at transfer rates under 3 MW, the economic performance is getting unacceptable.

Another aspect that was investigated was the influence of heat loss in the thermal storage. There were calculated simulations with an annual heat loss of 0%, 10%, 20%, 20%, 30% and 40% and a maximum heat transfer rate of 40MW, 5MW and 2MW. The results are rather astonishing because they show that heat loss does not really influence the economics much, but has a moderate effect of the overall profit.

The increase in the profit that a 12.000 MWh HTES generates compared to a 600 MWh traditional storage is reduced by less than 20% at a heat loss of 40% and a maximum transfer rate of 5MW.

The reason for why the heat loss has moderate influence on the profit is found in the fact that the lost heat is replaced by cheap production from the incineration.



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Hestehaven 21A
5260 Odense

## 4.2 Solar heating plant

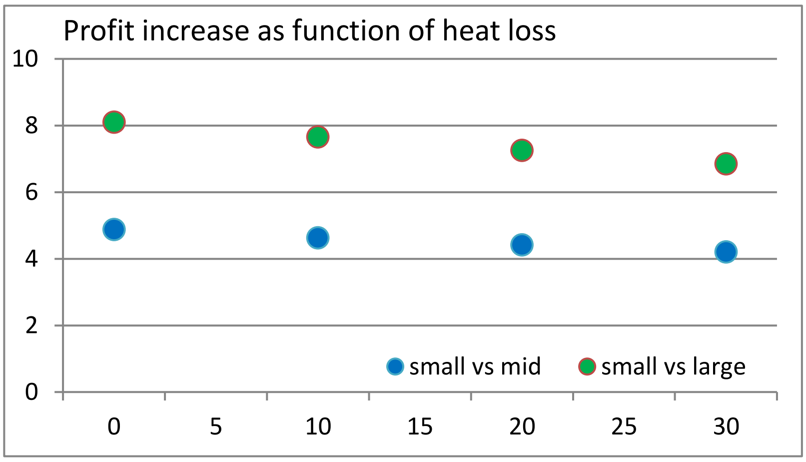
Solar heating plants produce large quantities of heat in the summer for almost no cost. Unfortunately, this is the time of the year where there is least need for that heat. To save the produced heat to be used in winter, solar heating plants are usually equipped with a pit-storage, which require a lot of space and therefore often have a limited capacity compared to the heating grids annual heat consumption. Normally, a solar heating plant supplies about 20% – 25% of the annual heat consumption. The limitation of the pit-storage size again limits the size of the solar plant itself. Solar panels cannot just be switched off, when the storage is fully charged, because the fluid in the panels would boil otherwise. As a result peak boilers have to support the heat delivery in the winter.

This is paradoxical, since the installation costs per square meter of solar heating systems usually decrease with increasing solar panel area.

We had the clear expectation that a large HTES would be a great advance for a solar heating plant, since HTES is an underground storage and the space above ground is not an issue.

There are performed various simulations with three different sizes of the solar heating plant, a small size plant, a medium size plant (50% larger than the small size plant) and a large plant (double size as small plant). For each plant size, simulations with a heat loss of the thermals storage of 0%, 10%, 20% and 30% were calculated.

If there would not be any limitation for the heat transfer rate to and from the storage then HTES would have a positive effect on the heat producer's bottom line. The diagram to the right shows the increase of the profit for the medium size plant compared to the small size plant (blue dots) and the increase of the profit for the large size plant compared to the small plant (green dots).



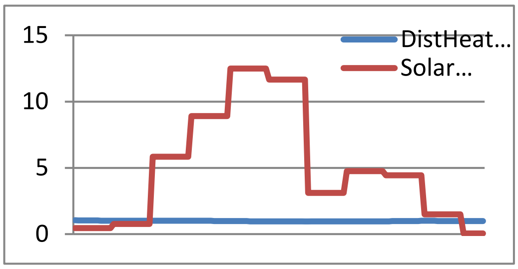

As an intermediate result it can be mentioned that:

- Larger solar heating plants mean increase in profit, but also larger construction investments
- Higher heat loss in the thermal storage means moderate decrease of the profit

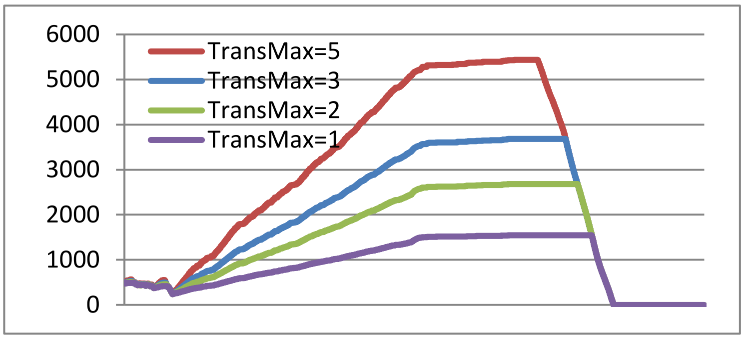
There have also been done simulations with variations of the maximum heat transfer rate, however here the simulation software came to its limit. It turned out, that the optimizations could not be calculated. The reason is as simple as obvious and astonishing in the same time.

Solar heating panels produce much more heat during sunny hours than the heat demand in the heating network at the same time. This excess heat has to be saved in a thermal storage. The amount of excess heat depends on the size of the heating grid (the heat demand in other words) and the maximum heat capacity of the solar heating system. Since we do not expect that HTES can deliver much more than 5 MW heat, there is the need of an additional (traditional) heat storage without any transfer limit, that can receive the excess heat fast enough.

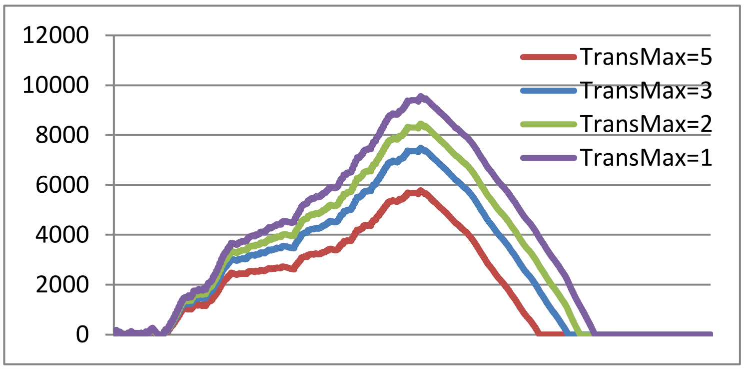
The diagram to the right shows that there are hours where the solar panels produce much more heat that can be consumed at the same time. Solar panels do not produce heat all the day long. Especially during the night, but also on cloudy days or during the winter, the heat has to be discharged from the heat storage fast enough to avoid peak boiler usage.




The diagram to the right shows the charging and discharging of a 12.000 MWh HTES at a medium size solar heating plant and different maximum heat transfer rates. During the summer, the storage is charged, but the storage is not filled totally before it is discharged in the winter. With a maximum heat transfer rate of 5 MW, not even 50% of the storage capacity is used.




As mentioned, the amount of heat that is produced by the solar panels and which cannot be charged immediately to HTES has to be saved into another heat storage with no transfer limits. At a maximum transfer rate to HTES of 5 MW, a secondary storage of almost 6000 MWh is needed which is even more that the maximum energy level in the HTES storage itself.




Due to the limitations of the heat transfer rate, HTES is probably less suitable for use as seasonable heat storage for solar heating plants.

## 4.3 Wood chips plant

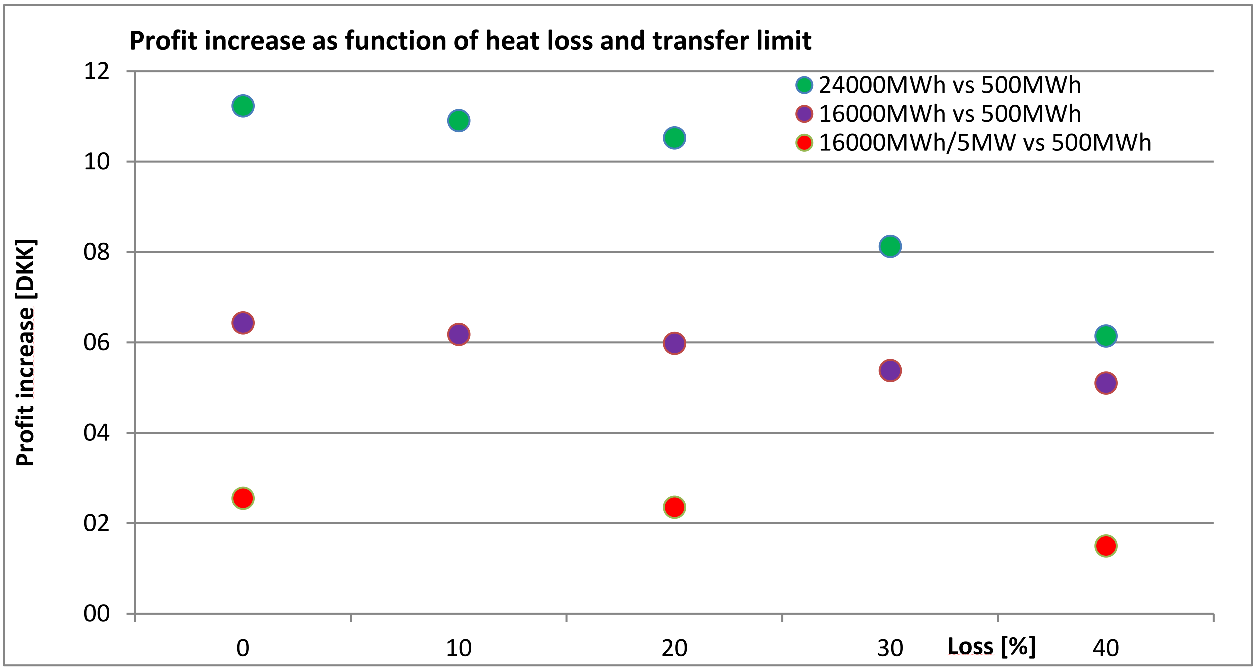
Units which burn wood chips, or other types of biomass as for example wood pallets, do also produce heat at fairly low cost. They might not be as cheap as incinerations but still are much cheaper than gas motors or turbines.

Comparable simulations as have been done for the incineration plant were made for a test plant that burns wood chips. The calculations gave slightly different values compared to the tests with the incineration, but confirmed the tendencies of the results.

OE3i ApS
Hestehaven 21A
5260 Odense

Major test results are:

- Larger heat storage means increase of profit (green vs. purple samples)
- Higher heat loss means moderate decrease of profit (values decreasing along the x-axis)
- Lower heat transfer rate means significant decrease of profit (purple vs. red samples)




The above diagram shows the correlation between storage size, heat loss, heat transfer rate and profit.

A thermal storage with a capacity of 16.000 MWh can increase the annual profit by around 6.400.000 DKK compared to a thermal storage of 500 MWh (purple dots). A heat storage of 24.000 MWh can even increase the profit by 11.200.000 DKK compared to the 500 MWh storage (green dots).

The influence of heat loss and transfer rate is higher is this scenario compared to incinerations, presumably because wood chip plant are producing at higher costs. A 16.000 MWh HTES loses 7% of the increased profit at a heat loss of 20% and loses 21% at a heat loss of 40%.

The consequences of a limitation in the heat transfer rate are even more dramatically: with a maximum transfer rate of 5 MW, the profit increase is 60 - 70% less compared with the profit increase that is possible without transfer limitations. The red dots represent the increase of the profit of a 16.000 MWh HTES and a maximum transfer rate of 5 MW compared to a thermal storage of 500 MWh. These values are much lower than the purple values which are the representative values without a limit on the transfer rate.

## 4.4 Influence of peak production at other costs

HTES generates an increase of the plants overall profit when expensive peak production can be replaced by cheap excess heat. The production cost for the peak boilers in the simulations were assumed to our best knowledge. Other types of peak units might give a lower profit increase if the production costs are lower than the costs that are used in the simulations. On the other hand, units, like oil boilers, might even be

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more expensive and give a better business case to HTES. In our simulations for the incineration plant, a 12.000 MWh HTES compared to a 600 MWh traditional heat storage reduces the peak boilers usage from 4,7% to 2,9%. In terms of energy this is approx. 5600 MWh. In other words: if the peak boilers operate at 100 DKK less than assumed, then the increase if the profit would have to be adjusted down with 560.000 DKK per year.

### 4.5 Heat effect and mass flow of water

The heat effect in a heating grid system is typically measured in Megawatt (MW) which is 1.000.000 Watt (W). Watt, also defined as 1 joule per second, quantifies the rate of energy transfer. The heat effect can be calculated by this formula:

$$Q = Cp\left[\frac{J}{kg\,°C}\right]\,qm\left[\frac{m^3}{h}\right]\Delta T[°C]$$

where

- Q: is the heat effect
- Cp: is the specific heat of water
- qm; is the mass flow of the water
- ΔT: is the difference between supply and return temperature

Since the permeability of the limestone has some limitations, the mass flow might be the parameter which is of most interest for HTES. The needed mass flow for a given heat effect can be calculated by rearranging above formula to:

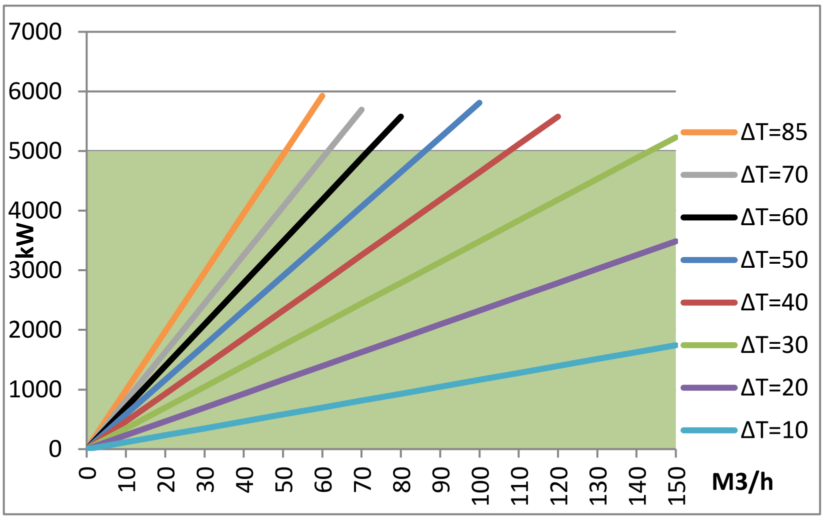
$$qm = \frac{Q}{Cp * \Delta T}$$

where ΔT is the temperature difference between the hot and cold water well.

To transfer 5 MW of water into the limestone, it is necessary to transfer:

- 143 $m^3$ at a ΔT of 30 °C
- 72 $m^3$ at a ΔT of 60°C
- 50 $m^3$ at a ΔT of 85 °C.

The diagram to the right shows the correlation of mass flow (x-axis), heat effect (y-axis) and temperature difference (sample lines).




# 5 Conclusions

Test scenarios and setups are chosen to the best of our knowledge. Operational settings and cost information are averaged from real world installations, were possible. Other settings may give better or worse results.

Charge / discharge periods (number of hours) depend on heat consumption profiles, annual heat consumption and heat production capacity and influence the profit.

Construction cost and operation costs for pumps etc. are not taken into account yet.

- A positive business case seems reasonable under certain circumstances.
- Best results are achieved when the price differences between cheap and expensive production units are high.
- A larger HTES means larger profit.
- HTES size should not exceed the excess heat capacity during the summer period.
- HTES size should not exceed the amount of heat produced by peak boilers during the winter.
- Heat loss has influence on the profit, but it seems that there is no big impact.
- Limitation of the heat transfer rate is crucial for a good profit.
- Solar heating plants are probably less suitable for HTES due to limitations of the heat transfer rate and the heat production profile of solar panels.

# 6 Recommendations

Phase 2 of the project is recommended to:

- Achieve real world settings from pilot customer for simulations
- Prove simulation results
- Include operational costs for pumps
- Include saved costs for avoided excess heat cooling
- Include loss in heat exchangers
- Improve simulations with seasonal optimizations

# 1 Extend

Initially it was decided to investigate the possibility of drilling and completing two wells in the Chalk section at a total vertical depth of 800 meters. With the aim of minimising the cost of drilling the wells, the possibility of using modern water well drilling technology for the drilling operation has also been assessed. The investigation has been split into three main parts where the first to parts (Well Design & Well Construction) is a technical feasibility of possible solutions and a proposal. The third part (Well Cost) is a cost estimate based on the proposed solution and on input from the three scenarios from the reservoir simulation.

# 2 Well Design

Two well designs were initially chosen regardless of geological investigations or other technical design related investigations. This was merely due to the fact that they are the two most obvious starting points/opposites, in order to clarify the gap between them and the possibility of drilling and completing semi-deep wells in a cheap manor and with the use of relatively simple drilling equipment.

- Vertical well. TD at 800m with a completion section length of 500m (300m – 800m).
- Deviated well starting off vertical. Building angle up to horizontal. Finishing off with a horizontal completion section in a depth of 800m. The completion section also having a length of 800m.

The wells have been designed with the IT tool, Compass, which is developed for the O&G industry.

The well pumps will be placed at an approximately 300 m depth and standard O&G casing sizes has been chosen since they are relatively easily reachable and have been proven durable in various situations. The base case casing setting depths has initially been planned as described below, taken the pump setting depth in to account.

- 0 – 50 m MD: 18 5/8” or 20” Conductor.
- 50 – 300(1183) m MD: 13 3/8” Production casing.
- 300(1183) – 800(1983) m MD: 9 5/8” Completion string/liner.

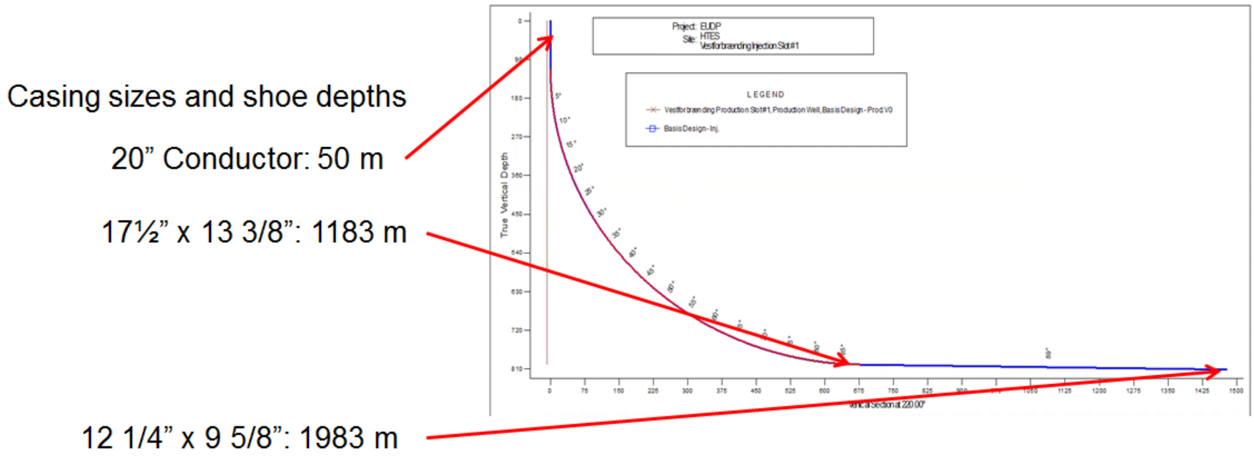



**Figure 1 Well trajectory and casing & section depths for the deviated / horizontal well**

## 3 Well Construction

Looking at directional drilling the deviated/horizontal well will be difficult to drill. Achieving good kick off and building angle already from 113 m will be challenging since the formations in this depth are relatively soft.

The proposed method from Awell for drilling HTES wells in the chalk formation is with a mobile water well drilling rig and reverse circulating (RC) the drilling fluid using airlift. Rigs like these are used for deeper water wells and the method has some advantages over 'direct flush' drilling. They are available with various specifications in different sizes. However, they are constructed to drill vertical and are not build for handling of additional drilling tools e.g. for steering purposes. Neither are water well drilling companies used to operating with additional drilling equipment during an operation and under these circumstances. The advice from Awell is therefore not to drill deviated/horizontal wells using this technique.

A study on the proposed drilling method from Awell has been made in order to clarify the critical gaps between the use of water well drilling equipment and the preferred drilling technique when drilling deeper geothermal or O&G wells. The conclusion points in the direction that there are some major unknowns in terms of well control, hole cleaning, flow rates, pressures, equipment behavior during semi-deep drilling and operational restrains especially when drilling longer deviated wells. Some of these unknowns may be lack of knowledge from both sides though. It should also be noticed that an RC water well drilling operation doesn't comply to all the same needs. And the specific rig looked at (Fraste FS 400) is rated to be able to drill 1500 m deep wells.

In addition to the general risks, other main risks when drilling deviated wells are:

- Water well drilling equipment mixed with directional drilling equipment has not been proven.
- Higher drilling parameters and casing weights requires more powerful equipment.

- Operational time and thus cost will increase.

If the wells are to be drilled deviated/horizontal it is therefore advised to look in to larger more appropriate drilling rigs for this purpose. These rigs and associated operations do come at a higher cost though.

# 4 Design proposal

Looking at the two design scenarios it is advised to drill vertical rather than drilling deviated/horizontal. This is also the conclusion when looking at the drilling technology.

It is highly unlikely that an RC water well rig will be capable of drilling a deviated/horizontal well. And drilling a vertical well with such a rig looks possible despite the unknowns. Since the needs are less complicated there is a reasonable possibility of drilling vertically will be successful.

Drilling vertical wells will likely require additional wells to be drilled in opposed to drilling more complicated horizontal and longer wells, in order to achieve the same necessary flowrates for the HTES system. However, the wells will be technical possible to drill at a much lower cost and with much more limited associated risks.

# 5 Well Cost

A time and cost estimate prepared by Awell on a vertical well is used as basis for the well cost estimate. The estimate has then been developed to fit the three scenarios from the reservoir simulations and reflects the time used to drill and complete a vertical well in the needed depths.

| Vertical well drilled by a water well drilling rig | | | | | |
|---|---|---|---|---|---|
| Well TVD [m] | Completion type | 13 3/8" shoe depth [m TVD] | Price estimate [DKK] | Duration [days] | Notes |
| 1060 | PVC Screens | 310 | 6.941.310,30 | 83 | Low Case Incl. well stimulation |
| 660 | PVC Screens | 310 | 4.666.737,20 | 54 | Best tech. Est. Incl. well stimulation |
| 660 | PVC Screens | 310 | 3.742.427,20 | 44 | High Case |

Prices exclude welltests, upper completion and disposal of drilling fluid

**Table 1 Time & Cost estimate for 1 well**

Looking over a span of several wells drilled in one continuous campaign it can be expected to have a positive effect on the well cost. This is due to learnings and constantly obtaining better knowledge about the given circumstances during the operations. The cost reflects a decrease in the optimisation with the highest potential in the beginning.

| | 1st Well | 2nd Well | 3rd Well | 4th Well | 5th Well | 6th Well |
|---|---|---|---|---|---|---|
| | Price estimate [DKK] | Price estimate [DKK] | Price estimate [DKK] | Price estimate [DKK] | Price estimate [DKK] | Price estimate [DKK] |
| Low Case | 6.941.310 | 6.372.123 | 6.036.312 | 5.846.117 | 5.835.276 | 5.835.276 |
| Best Technical Estimate | 4.666.737 | 4.284.065 | 4.058.295 | 3.930.424 | 3.923.135 | 3.923.135 |
| High Case | 3.742.427 | 3.435.548 | 3.254.495 | 3.151.951 | 3.146.106 | 3.146.106 |

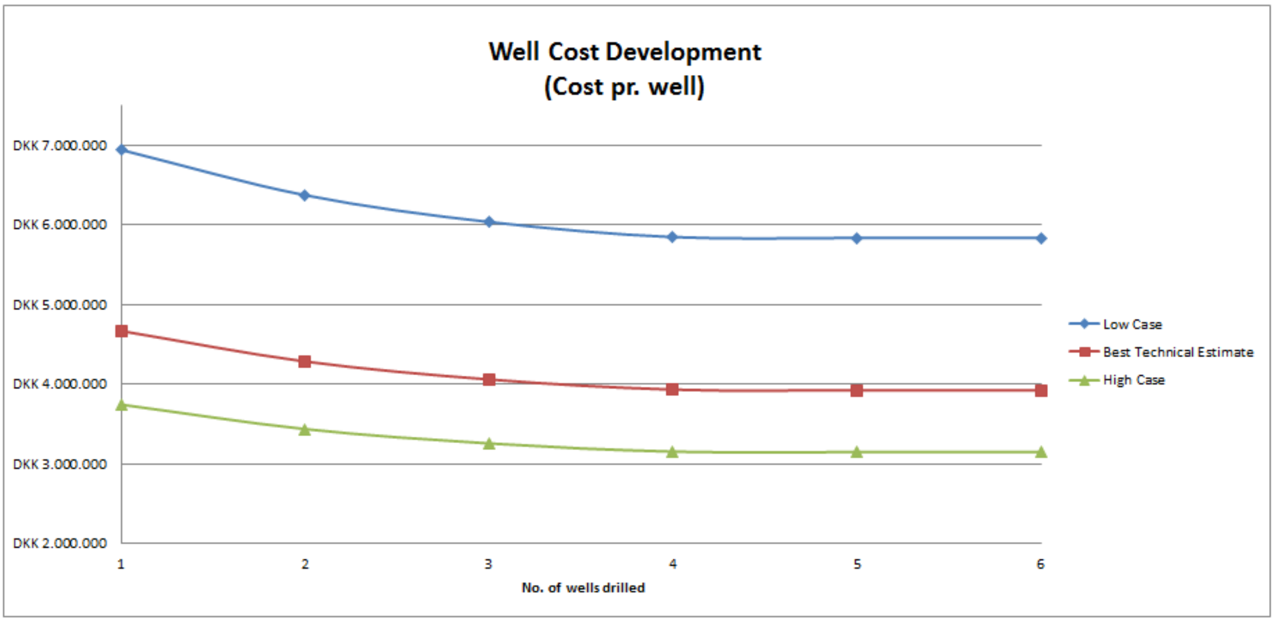



Figure 2 Well cost development

Finally the optimised well cost scenarios have been used to estimate a total well cost of the drilling campaign for each of the three scenarios from the reservoir simulations.

| | No. of wells | Estimated Cost [DKK] |
|---|---|---|
| Low Case | 16 | 95.000.000,- |
| Best Technical Estimate | 6 | 25.000.000,- |
| High Case | 2 | 7.200.000,- |

Table 2 Total well cost estimate

DTU Civil Engineering

# High Temperature Energy Storage – HTES project

## GEOTECHNICS AND GEOLEGY SECTION

Laura Paci, Irene Rocchi and Ida Lykke Fabricius
DTU | NORDVEJ BUILDING 119, 2800 KGS. LYNGBY

# High Temperature Energy Storage - HTES project

## Geotechnics and Geology Section

EUDP Jno 64016-0014

November 2017

**High Temperature Energy Storage - HTES project**

Geotechnics and Geology Section

Report R-389

2017

By Laura Paci, Irene Rocchi and Ida Lykke Fabricius

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# Preface

This report describes the geotechnical outputs elaborated by the DTU-Byg research group under the EUDP founded project HTES - High Temperature Energy Storage. The study is subdivided in four chapters, respectively *Introduction*, *Presentation of data*, *Discussion* and *Conclusion*. In Chapter 1 Introduction, the project aim, objectives and expected geotechnical outputs are listed. Chapters 2 Presentation of data and Chapter 3 Discussion show the available geotechnical and petrophysical dataset and the major findings. Finally, the conclusions are summarized in Chapter 4.

# Content

# Abstract

This research is part of the EUDP funded project HTES that aims at demonstrating the successful employment of Underground Thermal Energy Storage (UTES) in the subsurface of Copenhagen with a focus on the Chalk Group. The study investigates the geotechnical and petrophysical properties (i.e. stiffness and porosity) of the medium depth (800mbgl) Chalk Group. The majority of the geotechnical data available covers shallow depth, while deep well log data are fewer and of variable quality. In order to overcome the lack of information, this work evaluates the possibility to use Dan field in the central North Sea as an analogue for the chalk in Zealand comparing the effective stress and elastic moduli at the two locations. The maximum experienced effective stress for the formation is the same at the two geographical locations, which currently have different effective stress due to uplift and erosion of Zealand during the Neogene. The results shown were obtained calculating the maximum effective stress based on the burial anomaly as studied by Japsen (1998). In addition, the elastic moduli were calculated using the bulk density and the elastic P-wave velocity log data by means of the iso-frame model proposed by Fabricius (2003). The model allows us to estimate the elastic moduli by comparing the elastic modulus obtained by elastic P-wave measurements with the theoretical one obtained under the assumptions of either particles in suspension or cemented particles constituting a frame.

# Acknowledgements

This research used data provided by Geological Survey of Denmark and Greenland (GEUS), an independent research institute under the Ministry of Climate and Energy and GEO, an engineering consultancy within the fields of soil and water.

# 1. Introduction

This report summarizes the geotechnical results obtained by the research group at DTU-Byg Section of Geotechnics and Geology during the one year project HTES (High Temperature Energy Storage), an EUDP funded project (EUDP Jno 64016-0014) in collaboration with Ross Offshore DK (project leader), Ingeniør Huse, Awell, GEUS, OE3i and Geo. The aim of the project is to demonstrate the successful employment of geothermal energy and thermal energy storage in the subsurface of the greater Copenhagen area with a focus on the Chalk Group (target depth 800mbgl), and to identify the best locations where such technologies could be applied. The work programme of the HTES project is divided in four Work Packages (WPs) and requires collaboration and interconnection between the partners. WP1 focus on the review of existing knowledge of HTES and local subsurface data, WP2 use the information collected by WP1 to model the thermal storage potential and possible effects on the groundwater system. Based on results achieved by WP1 and WP2, WP3 evaluate the optimal borehole design. Finally, WP4 coordinates the other work packages and manages the project.

The DTU-Byg research group is involved in WP1 and WP2 providing information regarding the mechanical properties of the limestones to support WP3 to reduce the well drilling risks and maximize the well productivity. The DTU-Byg research group consists of three members:

- Ida Lykke Fabricius: professor of technical geology.
- Irene Rocchi: assistant professor of geotechnics.
- Laura Paci: geologist (M.Sc. University of Pisa), PhD student.

The objectives of this work group are:

1. Reviewing the existing knowledge of HTES and local subsurface data
   i.e. Geotechnical and Petrophysical properties.
2. Evaluate the Elastic moduli, Stiffness and Strength of the limestones (Zealand).
3. Evaluate the correlation of these properties with Porosity and Permeability.

4. Associate Geothecnical and Petrophysical properties to different facies in the limestones (Zealand).

We expected that the different degree of induration of the limestone formations in the Chalk Group influence their mechanical properties. The degree of induration (H) of a rock describes how easily it breaks apart on a scale from one to five (H1 poorly indurated rocks and H5 well indurated rocks) [1]. This property reflects the diagenetic history of a rock (Table 1).

**Table 1 Scale defining the degree of induration of a rock formation [2]**

| Degree of Induration | Description |
|---|---|
| H1: unlithified | The material can without difficulty be remoulded by fingers. Coarse material falls apart in dry condition. |
| H2: slightly indurated | The material can easily be cut by a knife and scratched by a nail. In coarse material single grains can be detached by using a fingernail. |
| H3: indurated | The material can be shaped by a knife but cannot be scratched by a nail. From coarse material grains can be detached with a knife. |
| H4: strongly indurated | The material can be scratched by a knife, but single grains cannot be detached with a knife. Fractures follow the grain contacts. |
| H5: strongly indurated | The material cannot be scratched by a knife. Fractures pass through the grains. |

H4 and H5 indistinguishable in limestone. In practice, H4 relates to the stiffest limestone, whereas H5 refers to chert. The expected outcome at the beginning of the project was to build a geographical distribution of the Elastic moduli, Stiffness and Strength, associated to  the limestone facies. The assessment of the mechanical properties of the limestones (reservoir hosting the thermal storage) is crucial to minimizomg the risks connected with the drilling phase (borehole and perforation stability) [3] and guarantee an optimal well and reservoir productivity (prediction of formation strength and well stimulation) [4] [5]. Evaluating the formation strength (reservoir pressure and stress conditions) is essential to avoid rock failure during well production, while estimating fracture pressure and height are a basis for well stimulation [6] [7]. Moreover, thermal fatigue in the limestones, due to the cyclic injection at extraction of formation water in connection with the thermal storage operations, could affects the formation strength. Gasc-Barbier et al (2014) demonstrate that cyclic temperature variation increase the risk of intergranular and intragranular cracking, inducing pore collapse [8]. In the North Sea, pore collapse has been observed during well production as a consequence of increasing effective stress and related decrease of pore pressure [9].

# 2. Presentation of data

Underground thermal energy storage (UTES) is an energy storage technology where natural underground sites are used for storing thermal energy. UTES technologies incorporate:

- Aquifer thermal energy storage (ATES): an aquifer (saturated and permeable underground layer) is used as storage medium. Thermal energy is transferred by extracting and re-injecting groundwater from the aquifer using wells.
- Borehole thermal energy storage (BTES): closed loop vertical heat exchangers installed underground (30-300 m depth, spacing range from 3 m to 8 m), which ensures the transfer of thermal energy into and from the ground (clay, sand, chalk, etc.).
- Pit thermal energy storage (PTES): lined, shallow pits filled with gravel and water as the storage medium.

In Denmark, the existing heat storage technologies applied include ATES, BTES and PTES, combing both heating and cooling as well as heat and power. The applications are both for single buildings (e.g. airports, industry, hotels, etc.) and for district heating or cooling. In particular, the preferred heat storage technologies are currently ATES and BTES in Zealand, concentrating in the Copenhagen area, and PTES in Jutland. This is because PTES, which are usually combined with solar plants, requires a large area for installation and land is more easily available and cheaper in Jutland compared to Zealand. Conversely, land requirements dominate the UTES in the Copenhagen area, making ATES a more attractive alternative. In addition, waste production is higher in Zealand, because of the population concentration and this makes energy production from waste incineration the green energy available in the greatest amounts. More than 30 heat storage systems were installed in the last 20 years in Zealand, 50% of which working as ATES. Typically 1 to 5 well dipoles are installed and the average capacity is 1900kW [10]

Based on the existing UTES plants that have been operating for some decades, experience is growing and following a similar move as hydraulic power, where a shift was observed towards mini-hydro starting a decade ago [11], UTES systems are also starting to concentrate on more widespread but limited production. In those countries where UTES systems are very widespread, such as the Netherlands, this has led to interference between neighbouring UTES and deep UTES may represent a necessary alternative.

In Denmark, most ATES are installed in shallow gravelly and/or sandy aquifer units below 50m from the ground level or limestone. Figure 1 shows that the top of Chalk Group (Upper Cretaceous limestones and Danian limestones) is between 0 and 200m in Zealand and in the northern part of Jutland, while it is between 200 and 600m in the west and south of Denmark. Therefore, two geological scenarios are encountered in Denmark with respect to the use of limestones in ATES systems, according to the geographical location. In Zealand and northern Jutland, the limestones are encountered from relatively shallow depth (0-30m) to 1-2km depth and typically are capped with stiff sediments such as Paleogene clays and glacial tills in Zealand or soft sediments in the north of Jutland.

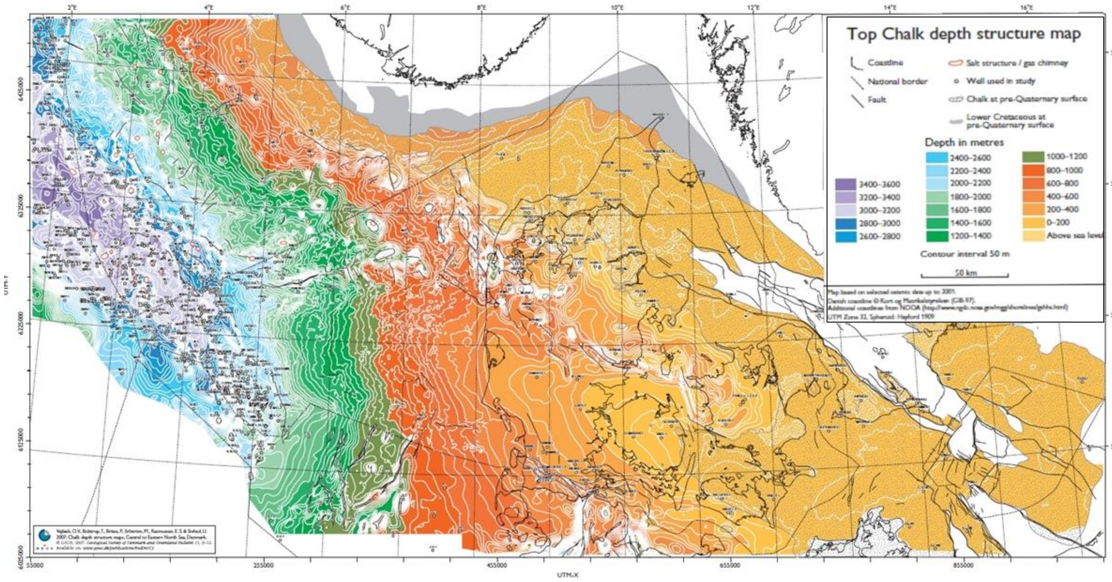


**Figure 1 Top Chalk Group structure map [12].**

For the purpose of UTES design, information regarding limestones must include hydrogeological, thermal and geotechnical properties. The few deep wells completed in Denmark are related to scientific investigation, gas storage, and petroleum exploration, and provide little geotechnical information (Figure 2). Sporadic geophysical logging of variable quality has been carried out, so that porosity and elastic P-wave velocity are available together with a lithological description. A wider, but shallow (maximum depth 100mbgl) number of geotechnical data (Triaxial shear test, Unconfined Compressive Strength – UCS test and Tensile test) was acquired in connection with the major public engineering infrastructures such as the Copenhagen Cityringen Metro and the Øresund Bridge projects. In the first case, a new circular metro line is under construction in the centre of the city with 17.4km tunnels and 17 new stations at 30mbgl. The Øresund Bridge is a combined railway and motorway bridge across the Øresund strait between Sweden and Denmark.

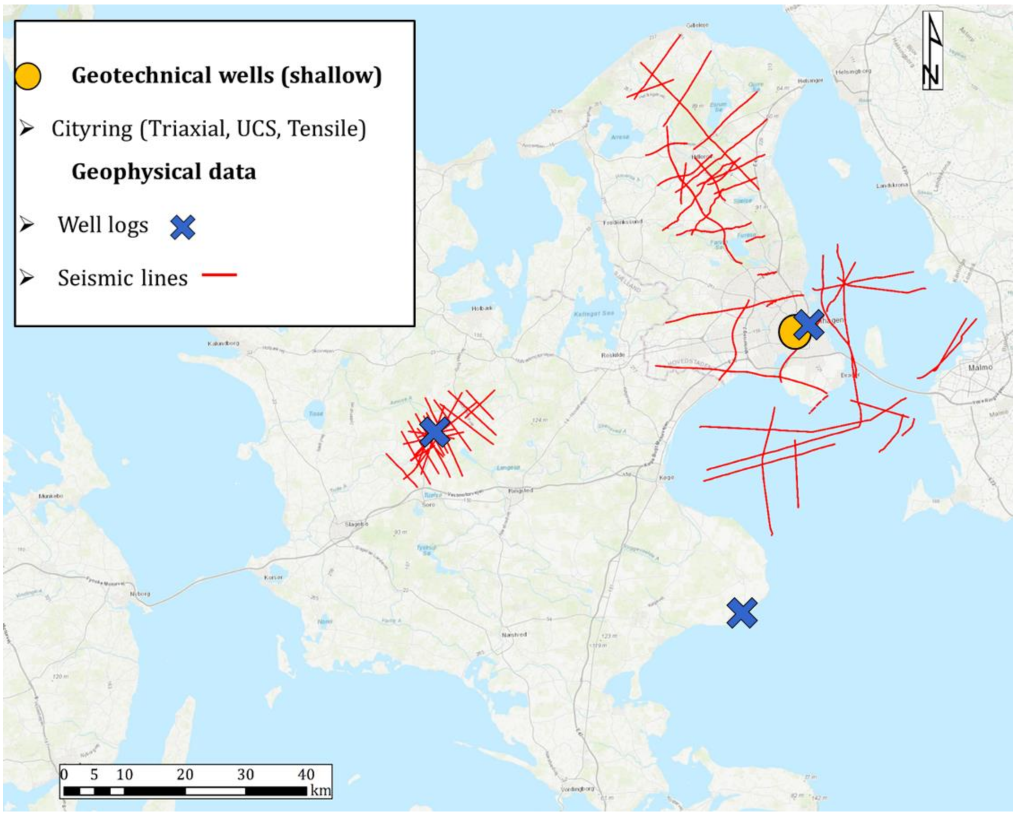


**Figure 2 Map of the available data.**

In order to overcome the lack of geotechnical information at depth, this study considers Dan field (North Sea), where both geotechnical and geophysical data are available, as a possible analogue for the Chalk Group in Zealand. Well log analysis and the estimation of the maximum effective stress (σ´) are used to assess this possibility. The effective stress links the magnitude of the mechanical response of a rock to variations in total stress (σ) and pore pressure (U), (Equation 1).

**Equation 1 Effective stress calculation. The Bulk modulus defines the resistance to isotropic compression of a rock.**

$$\sigma' = \sigma - \alpha U$$

$\sigma'$ = Effective stress

$\sigma$ = Load from overburden

$\alpha$ = Biot´s coefficient

$U$ = Pore pressure

$$\sigma = \rho_b * g * z$$

$\rho_b$ = bulk density

$g = gravitational\ acceleration$

$z = depth$

$$\alpha = 1 - \frac{K_{dry}}{K_{min}}$$

$K_{dry}$ = Bulk modulus

$K_{min}$ = Bulk modulus mineral

The Dan field is a hydrocarbon field located in the south-western corner of the Danish North Sea sector. The field has a dome structure and the main lithology is chalk. It is well known from the study of well cores and seismic lines that the Chalk Group is distributed across the northwest Europe, from the United Kingdom throughout the North Sea toward Denmark (Figure 1 and Figure 3). The Chalk Group contains an Upper Cretaceous-Danian limestone succession of chalk consisting mainly of the remains of planktonic algae and other pelagic organisms. The thickness of the limestones is greater in the Copenhagen area, between 900m and 1800m, as compared to in the Dan field (450-600m) [12]; while the burial depth ranges from over 3500m in the Central Graben to less than 100mbgl in the Danish Basin. Along the margins of the North Sea Basin, the thickness of the overburden deposits has been reduced due to the uplift and erosion during the Neogene. Therefore, the Chalk Group is overcompacted along the western and eastern margins due to the original greater burial depth. The magnitude of this event is approximately 1km and 750m respectively South of Bridlington, United Kingdom and in the North of Denmark (Aalborg, Copenhagen and Helsingør). In connection with the exhumation of the margins, the central North Sea area has experienced rapid burial of a maximum magnitude around 1.5km during the Late Cenozoic. Consequently, the chalk in the central North Sea is overpressured up to 20MPa at 2600m depth and underconpacted (Figure 4) [13]. Overpressure ($\Delta U$) is the difference between the current pore pressure and the calculated hydrostatic pressure at the depth (Equation 2).

**Equation 2 Overpressure (ΔU) and calculated hydrostatic pressure ($U_H$).**

$$\Delta U = U - U_H \Rightarrow U = \Delta U + U_H$$

$$U_H = \rho_f * g * z$$

$U = measured\ pore\ pressure$

$U_H = calculated\ hydrostatic\ pressure$

$g = gravitational\ acceleration$

$z = depth$

$\rho_f = density\ of\ pore\ fluid$

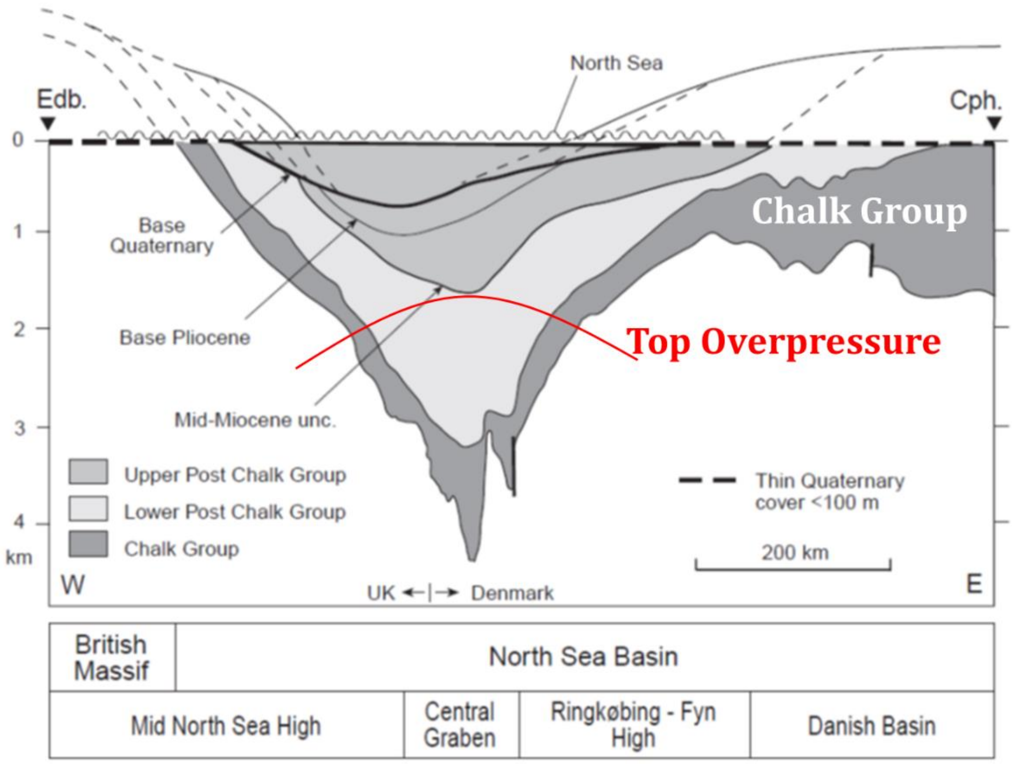


**Figure 3 Burial profile of the Chalk Group across the North Sea from Edinburgh (Edb.) UK, to Copenhagen (Chp.) DK with indication of structural elements (bottom of the figure) [13].**

Figure 4 shows the extension of the overpressured chalk in the central North Sea with a range between 5MPa and 20MPa. The area strikes North-Northwest covering a surface of around 425x125km$^2$. Japsen (1998) suggests that the chalk formation overpressure is proportional to the thickness of the late Cenozoic deposits (Upper

Post Chalk Group, Figure 3) and the region of overpressured chalk is limited by the Mid-Miocene unconformity at a depth greater than 1km (Figure 3).

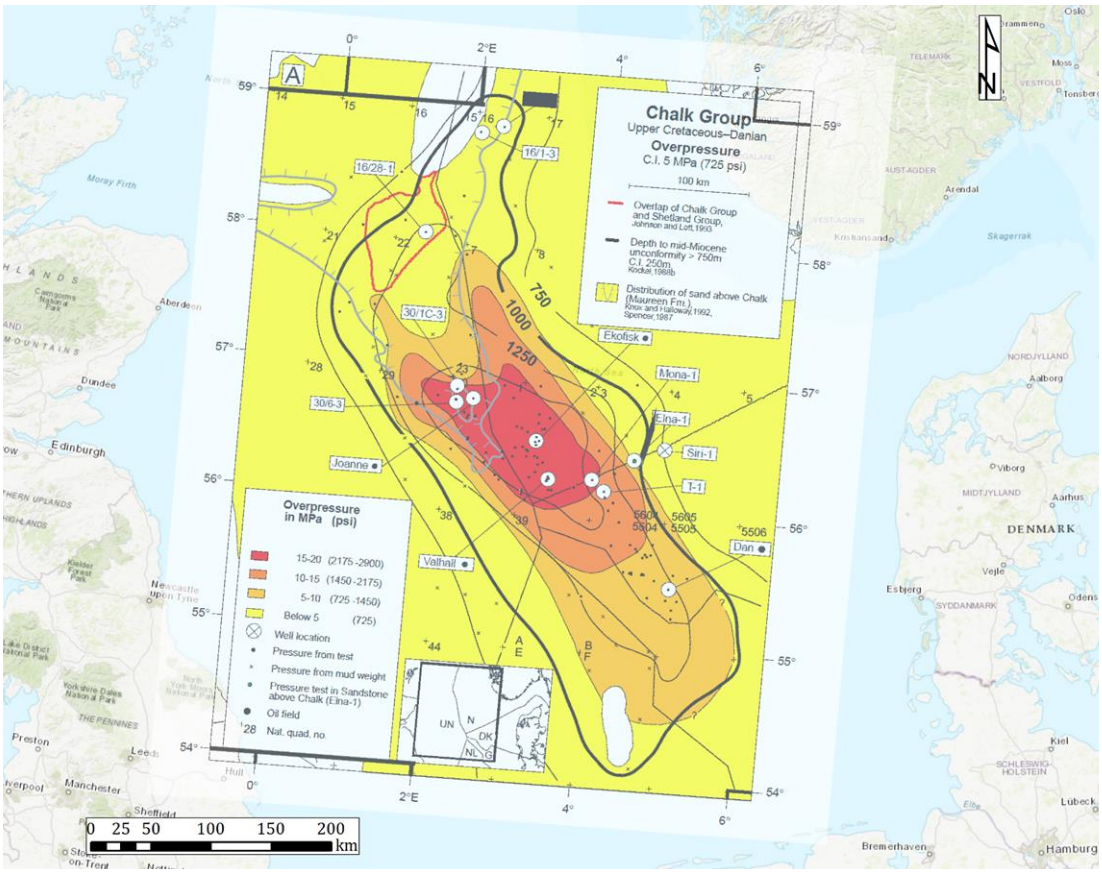


**Figure 4 Map of the areas affected by overpressure in the North Sea Basin based on pressure measurements and Chalk burial anomalies [13].**

# 3. Results

Based on the burial anomaly as studied by Japsen (1998), the effective stress of Dan field and the greater Copenhagen area is compared (Figure 5 and Figure 6). The maximum effective stress (σ´) for the formations are the same at the two geographical locations (5-15MPa), which currently have different effective stress due to uplift and erosion of Zealand during the Neogene. In Zealand, the present effective stress is below 5MPa, while it reaches a maximum of 15MPa in the Dan field. The Upper Cretaceous formation is found at much greater depth in the Dan field, resulting in a greater overburden stress. However, the effective stress is comparable to the maximum value encountered in Zealand (i.e. before uplift and erosion), due to overpressure in the Dan field. Overpressure has allowed a higher porosity to be retained in the Dan field, resulting in undercompaction of the chalk. Increase in maximum effective stress results in lower porosity. Therefore, any difference between stiffness and maximum effective stress relations results from cementation processes, which are not always porosity-reducing.

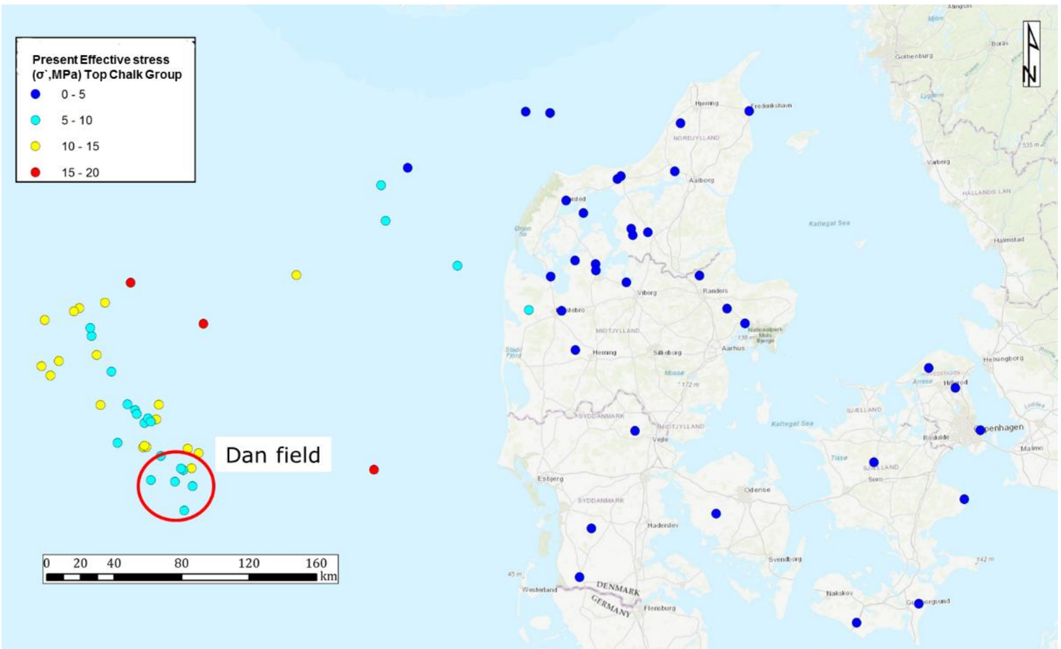


**Figure 5 Present effective stress at the top of the Chalk Group.**

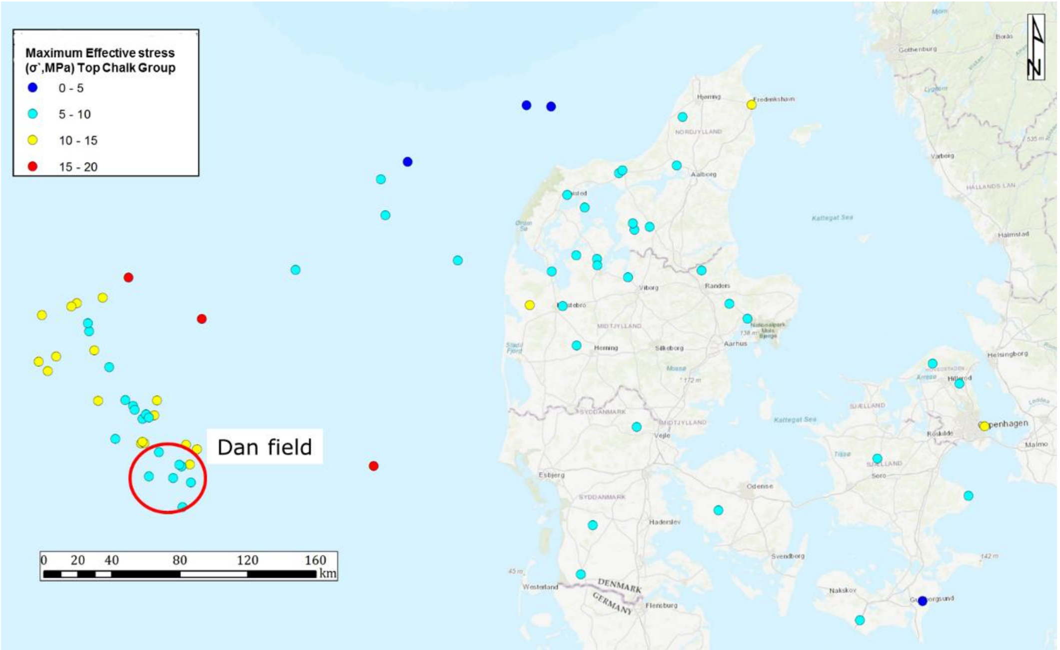


**Figure 6 Maximum effective stress at the top of the Chalk Group.**

The well logs used in this study originate from four wells: Margretheholm-1, Stenlille-1 and Stevns-1 located onshore Zealand and M-10X in the North Sea (Dan field). Based on elastic P-wave velocity and bulk density data the mechanical properties of the Chalk Group in Zealand are estimated and compared with those of the Dan field. The elastical properties (in casu Young´s modulus and Poisson´s ratio) are obtained by means of the iso-frame model proposed by Fabricius (2003). The model allows to estimate the Elastic moduli by comparing the elastic modulus obtained by P-wave measurements with the theoretical one obtained under the assumptions of either particles in suspension or cemented together in a frame [14]. Figure 7 shows the estimated mechanical and petrophysical properties of the Chalk Group at the two different geographical locations. In the top of the figure, Young's modulus (E, which is a measure of the stiffness of the rock) from well logs (right) and laboratory test (left) is compared. The elastic modulus of the Copenhagen Limestone (Danian) does not follow a clear trend and covers a wide range from hundreds of MPa up to 50GPa, while the elastic modulus based on deep well log data presents an overall increase with depth. The Poisson´s ratio describes the phenomenon in which a material tends to expand in directions perpendicular to the direction of compression (i.e. the ratio of transverse strain to axial strain). It ranges between 0.0 and 0.5, where an incompressible material deformed elastically at small strains would have a Poisson's ratio of exactly 0.5. In rock engineering application, the Poisson´s ratio of a rock formation estimates the stress around underground opening (e.g. boreholes) and reflects the stiffness of the rock [15]. The value of the Poisson´s ratio increases slowly with depth reflecting the increasing stiffness of the chalk.

The Upper Cretaceous limestones (depth interval: 700-1500mbsl) on average show low porosity between 10% and 20%, while the Danian limestones (depth interval: 30-400mbsl) have a higher average porosity, around 30-40% as seen in Figure 7. The Elastic P-wave velocity tends to increase slowly with the burial (i.e. higher contact cementation) and to decrease with increasing porosity. Both the mechanical and petrophysical properties plot of Stevns-1 are wildly scattered, reflecting a poor quality log. Figure 8 shows the cross-plot of Young's modulus (E) and Porosity of the Chalk Group at the two locations. Dan field chalk has Porosity – E modulus relationship distinctly different from chalk of Stenlille-1, Margretheholm-1 and Stevns-1. Despite the fact that Dan field has comparable maximal effective stress, the rock physic modelling does not indicate a clear relationship between the two locations. The reason is probably that although the stress history is comparable, the temperature history is not because of the difference in actual maximal burial.

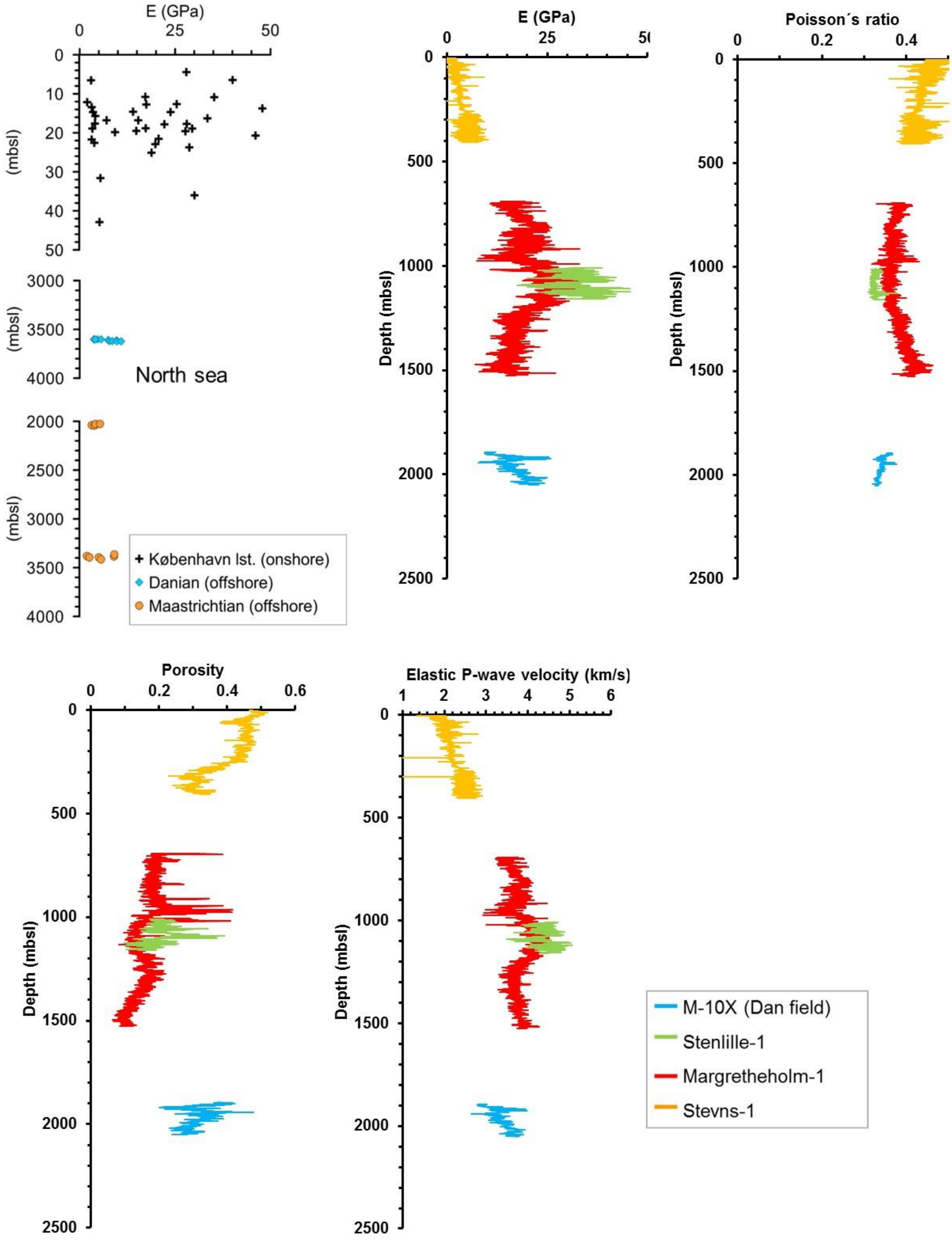


**Figure 7 Elastic and petrophysical properties of the Chalk Group in Zealand and North Sea (Dan field).**

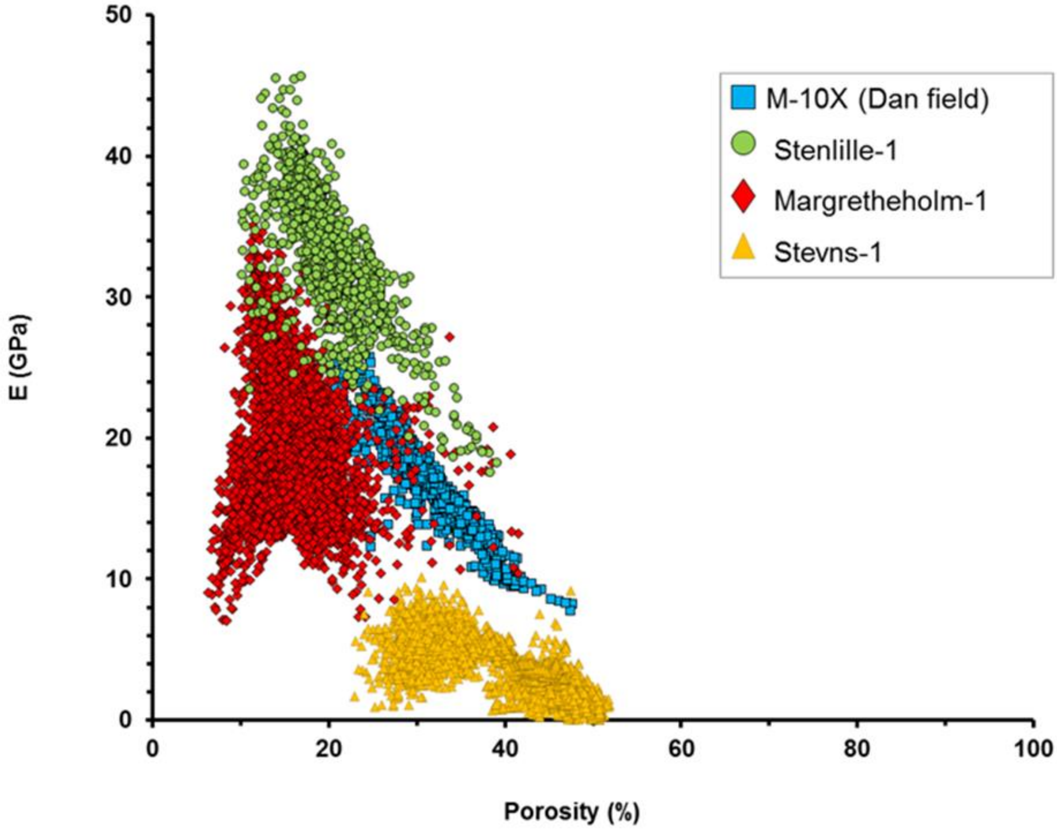


**Figure 8 Cross-plot: Young’s modulus (E) versus Porosity.**

# 4. Conclusion

This study underlines that the sparse geotechnical information and poor quality well log data are the main challenges when estimating the geotechnical and petrophysical properties of the Chalk Group in the greater Copenhagen area. There are no available geotechnical data for chalk of Copenhagen area in target depth interval. Dan field Chalk could not be used as an analogue for the Copenhagen chalk because, from effective burial modelling, Dan field has comparable maximal effective stress, but from rock physic modelling, Dan field chalk has Porosity – E modulus relationship distinctly different from the chalk of Stenllile-1, Margretheholm-1 and Stevns-1, caused by its different temperature history.

The DTU-Byg group underlines the necessity of retrieving deep chalk cores from Copenhagen area to provide material for pertinent geotechnical testing. Moreover, it is recommended that geophysical logs must be of high quality commercial standard in order to provide quantitative information. Finally, it is advised to study the effect of water injection on the geotechnical properties, because experience from the North Sea indicates potential enhanced pore collapse.

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DANMARKS OG GRØNLANDS GEOLOGISKE UNDERSØGELSE RAPPORT
2017/22

# Examining the possibilities of establishing thermal storage in the chalk/limestone aquifer in the greater Copenhagen area

## Phase 1 of project HTES, High-Temperature Energy Storage

Lars Kristensen, Anders Mathiesen, Carsten Møller Nielsen,
Morten Bjerager, Claus B. Ditlefsen, Ingelise Møller,
Per Rasmussen, Lars Henrik Nielsen
& Torben Sonnenborg

**SUMMARY**
**of Project Report**

# Contents

# Dansk resumé


GEUS har vurderet lagringspotentialet i kalken indenfor det Storkøbenhavnske område. Vurderingen er baseret på den eksisterende viden om undergrunden, bl.a. ud fra data fra boringer, kernemateriale, borehulsmålinger, seismiske data og litteratur af geologisk karakter. Kalken består af flere enheder med forskellig sammensætning og reservoiregenskaber, og GEUS vurderer, at den såkaldte Hvidskud Member vil være bedst egnet som lagerenhed. Denne enhed ligger i ca. 600 meters dybde, men dybden varierer på tværs af det Storkøbenhavnske område som følge af, at kalklagene har været udsat for forskellig grad af indsynkning, opløft og erosion.

Med henblik på at udpege egnede steder for etablering af et eventuelt lager, har GEUS karakteriseret det enkelte kalklag med hensyn til fordeling af porøsitet, permeabilitet, temperatur og termiske egenskaber. Hvert lag betragtes som en strømningsenhed.

På baggrund af de geologiske og reservoirmæssige forhold har GEUS vurderet mulighederne for at etablere et termisk lager ved Vestforbrænding og i nogle kendte brudzoner (forkastningszoner). For hver prospekt-type har GEUS udarbejdet en prognose med forventede lagtykkelser og variation i reservoirparametre. De udførte undersøgelser og de opstillede prognoser peger på, at kalken kan anvendes som lagringsmedium, men de tilhørende produktions- og injektionsrater er vanskelige at prædiktere ud fra det foreliggende datamateriale, bl.a. på grund af et ringe kendskab til den effektive permeabilitet.

Permeabiliteten kan være høj i og omkring forkastningszoner, men der er knyttet særligt høje usikkerhedsfaktorer til genindvinding af det lagrede (varme) vand fra områder med forkastninger, bl.a. kan afkølingsgraden vise sig at være høj, og desuden er der mulighed for tab af det opmagasinerede vand. På den baggrund anbefaler GEUS, at der etableres et anlæg på en lokalitet, der ligger udenfor større brudzoner.

GEUS har opstillet en geologisk model for kalken samt udført en række reservoirsimuleringer af mulige strømnings- og temperaturforløb, herunder prædiktion af potentielle produktions- og injektionsrater. Der er i den forbindelse foretaget et 'følsomhedsstudie' samt simuleret forskellige løsningsmuligheder for at opnå øgede produktions- og injektionsrater.

Herudover har GEUS undersøgt, om de ændrede tryk- og strømningsforhold i lagerzonen påvirker grundvandszonen (0–250 m) i et vist omfang. De udførte simuleringer viser imidlertid, at der ikke er konflikt mellem lager- og grundvandsinteresser.

Da det foreliggende datamateriale er relativt sparsomt, anbefaler GEUS, at projektet fortsætter med en fase 2, der har til formål at tilvejebringe et mere nøjagtigt og omfattende datamateriale. I den forbindelse anbefales det, at der bores en pilot boring til 800 meter dybde, hvori der tages én eller flere kerner i den påtænkte lagerzone (400–800 m). Herudover bør der ubetinget foretages en produktionstest med henblik på at bestemme kalkens effektive permeabilitet, og desuden bør der udføres en række borehulsmålinger ved hjælp af sonder (logs).

Det anbefales endvidere at overveje anvendelse af brøndstimulering og at etablere et vandbehandlingsanlæg. Formålet med vandbehandlingen er at reducere omfanget af udfældninger i installationer og i selve reservoiret.

# 1. Preface and description of project

The project 'HTES' (High Temperature Energy Storage) aims at demonstrating a new seasonal storage technology. The HTES project examines the possibilities of establishing thermal storage in the chalk/limestone aquifer within the greater Copenhagen area in the depth range 400–800 metres.

The project 'HTES' is funded by the 'Energy Technological Development and Demonstration Program', EUDP. The EUDP Project ID is 64016-0014 within the EUDP technology class "Smart grid and Systems".

The first phase of the 'HTES' Project consists of 4 work packages (WPs);

- WP 1. Review of existing knowledge of HTES and local subsurface data
- WP 2: Model simulation of the storage potential and possible effects on groundwater system
- WP 3: Well design
- WP 4: Project management

The purposes of WP1 and WP2 are:

- To collect and **review** the existing data material, including:
  - **Geological data,**
  - **Geotechnical data,**
  - **Geophysical data**
- To set up a numerical groundwater and reservoir model.
- To pin-point (map) possible sweet spots or prospects.
- To set up a geological well prognosis with reservoir parameters for each prospect.

**The present summary report focuses on the geological, geophysical and hydrogeological evaluations and presents the results of the reservoir simulations. A more detailed report, including further documentation of the work carried out, will be prepared.**

G E U S

Energiteknologisk udvikling og demonstration

# 2. Introduction and background

The **first phase** of project ‘HTES’ reviews the existing knowledge on thermal energy storage, evaluates relevant geological and geophysical data from the study area and sets up a numerical groundwater and reservoir model. This phase also includes an evaluation of information from geotechnical wells. The aim of the data compilation is to evaluate existing knowledge and data, and on this basis provide a geological well prognosis accompanied by reservoir parameters for a pilot well, complying with standard water well drilling equipment. Phase 1 also comprises work on searching for potential prospects (sweet spots) within the depth range 400–800 m, corresponding to the planned storage depth. At these depths, chalk dominates the lithology of the aquifer system.

Project ‘HTES’ utilizes information from a number of High-Temperature Aquifer Thermal Energy Storage systems located in Germany, France, Holland and England. Most commonly, these storage systems utilize sandstone aquifers, but the German plant at Dingofing involves storage of surplus energy in a Jurassic limestone aquifer at about 500 m depth. The idea behind the German storage system is very similar to the concept of the planned Danish HTES system: Hot water is injected into the aquifer via an injection well during the summer period, and the same well is used for producing the stored water during the winter period. During summertime, a separate production well supplies the necessary cold water and via a heat exchanger, the water is heated to up to 90°C (or the best operational temperature). Subsequently the water is injected into the aquifer (and stored). During wintertime, the production well is converted into an injector. In this way, the formation water circulates in a closed system, and no excess water is added (**Figure 1**).

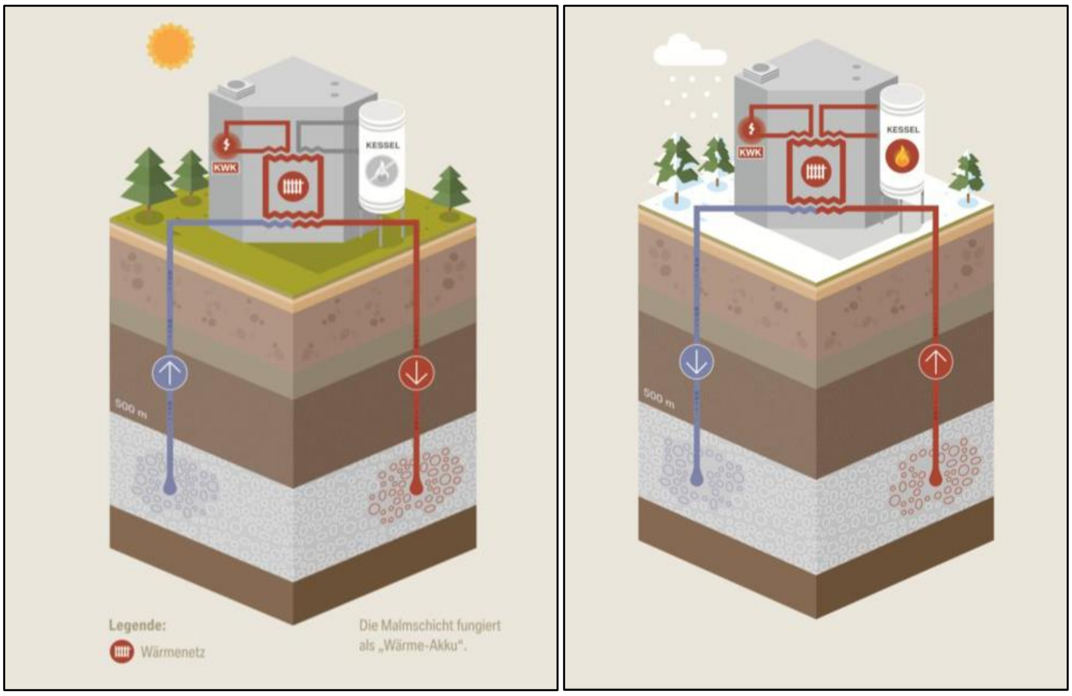



**Figure 1:** ***Summer*** *operation (left): Loading the storage via a ‘Warm Well’ (red). Injection of water that has been warmed-up via surplus energy from a combined heat and power plant system (CHP). The ‘Cold Well’ (blue) supply the formation water needed for running the system.* ***Winter*** *operation (right): Extraction of the injected hot water using the ‘Warm Well’. The water is used as a heat source, e.g. for the district heating system. The cooled water is re-injected using the ‘Cold Well’. The closed loop limits pressure and geochemical disturbances.*

# 3. Geology and reservoir characterization

A number of deep well are drilled within the greater Copenhagen area, and data from these wells show that the subsurface consists of an up to 2 km thick package of chalks and limestones. The Danian limestone section, which generally is relatively thin (c. 100 m), is overlain by a quite thin cover of sandy and clayey deposits (<100 m). The scheme below presents a stratigraphic subdivision relevant for this study (**Table 1**).

**Table 1: Stratigraphic scheme of the Upper Cretaceous – Quaternary in the Copenhagen area**

| Chronostratigraphy Geological age | | Lithostratigraphy Reservoir units** | Local Member |
|---|---|---|---|
| Quaternary | | Quaternary undiff. | |
| Paleocene | Selandian | Kerteminde Marl Fm<br>Lellinge Greensand Fm | |
| Paleocene | Danian | København Limestone Fm | |
| | | Bryozoan Limestone unit (Stevns Klint Fm) | |
| Late Cretaceous* | Maastrichtian | Sigerslev Mb | Højerup Mb |
| | | Rørdal Mb | |
| | | Hvidskud Mb | |
| | E. Maastrichtian–L. Campanian | Boesdal Mb | |
| | Late Campanian | Flagbanke Mb | |
| | L. Campanian–Cenomanian | Lower Chalk unit (informal) | High GR unit |
| | Santonian and older | - | |

* In the Danish onshore area, the late Cretaceous chalks belong to the informal 'Chalk Group' (Nielsen and Japsen 1991). ** The nomenclature is based partly on information from Surlyk et al. (2006, 2013) and Stenestad (1976).

The limestone section consist of two key units in the study area: the 'København Limestone Formation' and the 'Bryozoan Limestone unit'. The København Limestone is composed predominantly of sand-size carbonate grains and limestone. The Bryozoan Limestone is dominated by bryozoan-rich limestone, occasionally with large amounts of clay-size and silt-size carbonate grains.

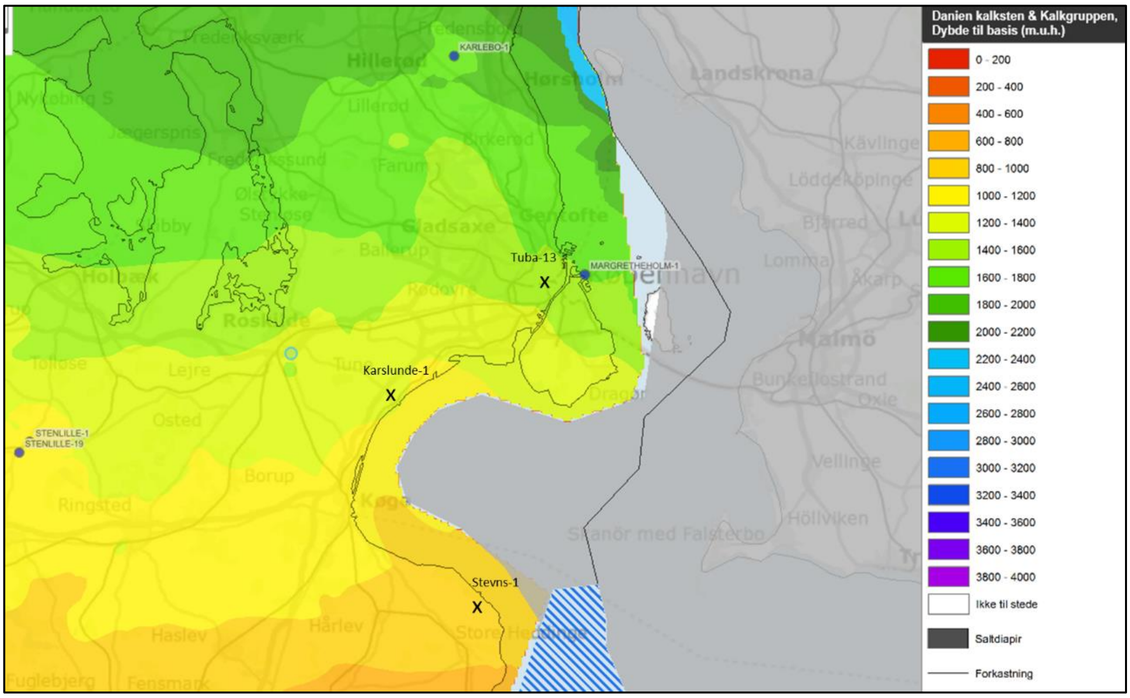
The planned storage zone is located primarily in the deeper buried Maastrichtian and Campanian chalks. Chalk is a white, soft carbonate rock; a form of limestone composed of calcite originating from shells of micro-organisms (coccoliths). Apart from the presence of chert nodules and small amounts of clay, the chalk is particularly homogenous, but the degree of cementation and the amount of natural fractures vary considerably with depth. In order to get additional information about the chalk in the central Copenhagen area, GEUS carried out a number of core analyses on the Tuba-13 drill core ("tunnelbane boring" located at Copenhagen Central Station).

The stratigraphy, lithology and reservoir parameters vary considerably within the study area, both vertically and horizontally – and this situation is a challenge for the geological assessment. The lithostratigraphic units are also considered flow units (reservoir units) and thus the unit subdivision is essential, both from a geological and reservoir technical point of view. The lithostratigraphic subdivision of the Upper Cretaceous chalk units into Sigerslev, Rørdal, Hvidskud, Boesdal and Flagbanke Members is based on outcrops and fully cored boreholes sections located largely at Stevns/Møn (cf. Surlyk et al. 2006, 2013). The GEUS subdivision of the drilled section in each well is based on log data supported by results of biostratigraphic analyses. GEUS screened 47 cuttings samples from the limestone and chalk sections in the Margretheholm-1 well and carried out both nannofossil and foraminfera analyses to support the stratigraphic subdivision. The unit subdivision is also based on interpreted seismic data.

The reservoir quality generally decreases with depth and with increasing clay content and diagenetic carbonate precipitation. **Overall, the Sigerslev and Hvidskud Members are considered the best reservoir units** due to a general clean chalk composition and relatively shallow burial. A general shallowing and thinning of the chalk units occurs towards the south, causing better reservoir quality of the individual units in this direction.

The national groundwater mapping program initiated by the Danish Government in 1999 resulted in a detailed description of Danish aquifers – and as part of the project, areas with *specific groundwater interests* as well as areas with *general groundwater interests* were pointed out. The major part of the greater Copenhagen area is assigned to the category: 'specific groundwater interests'. West of the central Copenhagen and on the southeast of Amager, areas with 'general groundwater interests' are designated. Only in the central harbour area and on western Amager a zone with limited groundwater interests is found.

No cores are available from the chalk section within the depth range 400–800 m in the greater Copenhagen area, but core analysis from Stevns-1, Karslunde-1 and Tuba-13 give an indication of the matrix permeability, despite the cores are cut in the depth range 0–450 m. No well tests have been conducted in the interval 400–800 m and the amount of natural fractures is very limited for chalk found deeper than 300 m, meaning that the effective permeability of the reservoir chalk is not known. A map showing the **well locations** is inserted below. The coloured base map corresponds to a base chalk depth structure map (metres) available from the GEUS WebGIS portal. The map also gives an indication of the total thickness of chalk and limestones sections.



The available conventional core analysis data makes it possible to establish a reliable porosity-permeability relationship (poro-perm plot), which form the basis of estimating the matrix permeability for a given porosity value. It is thus possible to relate a log-derived porosity to a matrix permeability estimate. The chalk matrix permeability is generally low or even very low, i.e. in the order of 1–10 mD.

Reservoir parameters that overall characterize the chalk of the planned storage zone - as well as reservoir parameters representative of chalks found outside the storage area - are listed below. The reservoir parameters characterizing the storage zone are estimated by GEUS on the basis of core analysis data from nearby wells and interpreted log data from deep wells located outside the planned storage area. The 'best reservoir zone' corresponds primarily to the Hvidskud Member (refer to Table 1).

| Best reservoir zone at a specific site or well | Approx. Depth (m) | Approx. Porosity | Approx. matrix Permeability | Source |
|---|---|---|---|---|
| Møns Klint | 0 | 42% | 3–5 mD | Measured on core plug samples |
| Stevns-1 | 200 | 38–45% | 3–8 mD | |
| Stenlille-1 | 500 | 24% | 1 mD | Log interpretation |
| **Planned storage zone** | **600** | **30%** | **2 mD** | **GEUS assessment** |

Remark: The effect of fracture presence and the effect of faulting on the permeability estimates will be discussed later. Note that the permeabilities listed above are matrix permeabilities.

The expected temperature in the storage zone is calculated on the basis of an average temperature gradient of 22°C/km; i.e. **Temperature (on avg.) = 8°C + 22°C/km x Depth[km].**

## 3.1 Sandy chalk and thin sandstone beds

A sandy chalk section was encountered in the Margretheholm-1 well in the depth range *c.* 900–950 m, and this interval may form a potential storage section. It appears from the mud loss record that the sandy section is characterized by rather high permeability.

# 4. Conceptual model and prognosis for the Vestforbrændring site ('prospect')

Herein the quoted word '**prospect**' denotes a potential geothermal site (cf. heading above). The Vestforbrænding site is located in Glostrup/Ejby close to an intersection point between two seismic lines (**Figure 2).** The depth to the various surfaces and geological units can therefore be calculated with good confidence.  A geological well prognosis accompanied by reservoir parameters is tabulated below (Table 2); observe that the København Limestone unit is not present at the Vestforbrænding site.

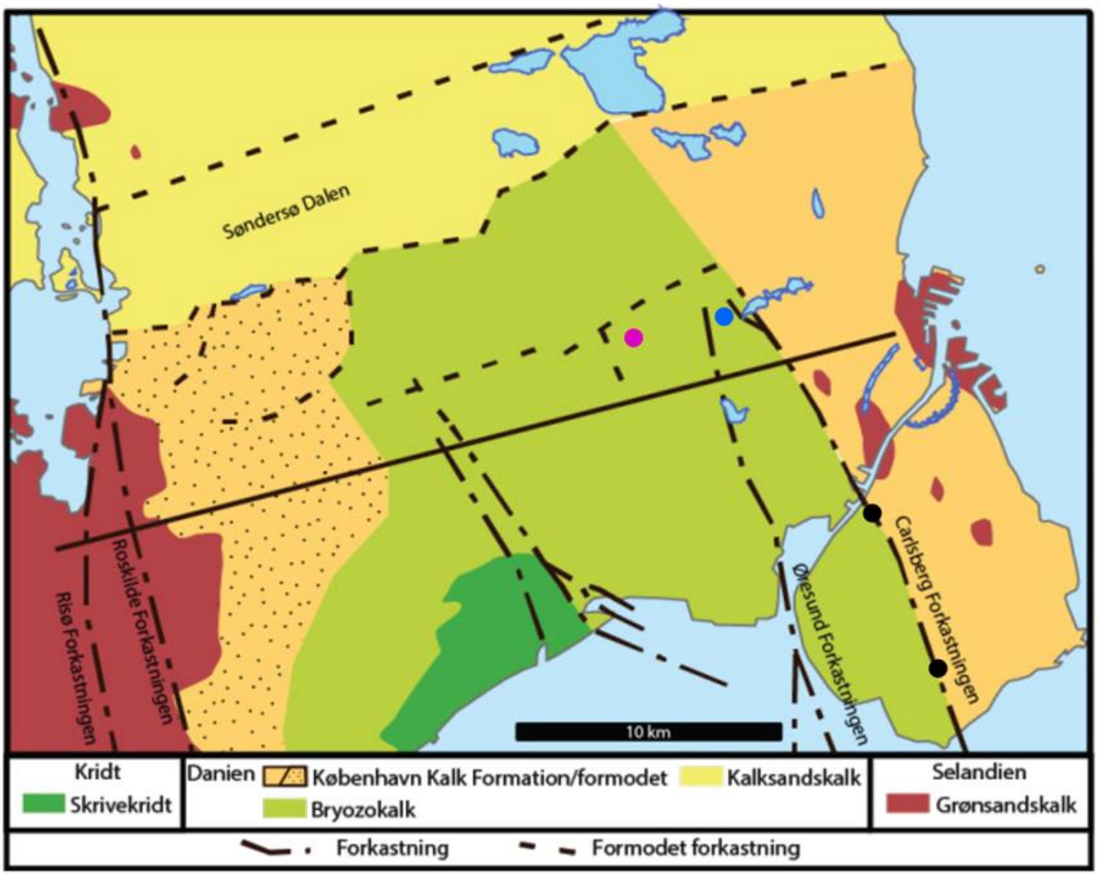



**Figure 2:** *Location of the Vestforbrænding site (pink dot), the faulted site at line HGS-001 (blue dot), and the Carlsberg Fault zone including two selected sites (black). These four sites are considered relevant for examining the possibilities of establishing thermal storage in the chalk section. The Vestforbrænding site is situated close to an intersection between two seismic lines (HGS-001 and HGS-005). On the Amager Island, a black dot indicates intersection between the Fault Zone and a seismic line. The figure also points out pronounced fault zones other than the Carlsberg Fault. In addition, the map provides an overview of the limestone and chalk types related to the pre-Quaternary surface (from Jakobsen et al. 2017). The ENE–WSW line refers to a cross-section (not shown).*

The planned storage depth (400–800 m) encompasses the Hvidskud, Boesdal and Flagbanke Members of Maastrichtian–Campanian age, and the rock-forming material of the storage zone corresponds probably to rather homogeneous chalk with a few natural fractures. The Danian is represented by bryozoan limestone with possible intercalations of chalk mudstone. The geological prognosis at Vestforbrænding is based on descriptions of samples from nearby shallow boreholes, seismic interpretation (Larsen 2016), and correlation with fully cored boreholes combined with information from petrophysical well-logs in the region. A separate document (report) prepared for this HTES study outlines the stratigraphic break down in further detail, and this report also includes a description of the composition of each chalk Member.

The porosity and permeability vary with depth and member. Well data from Margretheholm-1, Stevns-1 and Karslunde-1 provide the reservoir parameters for the Hvidskud Member, whereas the reservoir parameters for the Boesdal/Hansa and Flagbanke Members are based on data from Margretheholm-1, Stevns-1 and Stenlille-1.

The site is situated at the boundary between areas with specific and general groundwater interests, and thus it must be ensured that deep storage in the chalk at this site does not affect the groundwater resource negatively. The groundwater aquifer at the Vestforbrænding site consists of Bryozoan Limestone, and the direction of the groundwater flow in the limestone aquifer is estimated to be from the NW. This observation is based on information from a hydraulic head map constructed by Region Hovedstaden in 2009.

**Table 2: Well prognosis for the Vestforbrænding site** (for location, see Figure 2)

| **Vest-** | | Top | Base | Thick | Top | Base | Por. | Matrix | Effective |
|---|---|---|---|---|---|---|---|---|---|
| **forbrænding** | **PROGNOSIS** | (mMD) | mMD | (m) | b.MSL | b.MSL | (%) | Permeability (mD) | |
| Quaternary | Quaternary undiff | 0 | 12 | 12 | -16 | -4 | N/A | N/A | N/A |
| DANIAN | København lst. | 12 | 12 | 0 | -4 | -4 | N/A | N/A | N/A |
| DANIAN | Bryozoan lst. | 12 | 48 | 36 | -4 | 32 | 38 | 30 | 100 |
| MAASTR. | Sigerslev Mb | 48 | 210 | 162 | 32 | 194 | 35 | 3 | 20 |
| MAASTR. | Rørdal Mb | 210 | 260 | 50 | 194 | 244 | 29 | 2 | 10 |
| MAASTR. | Hvidskud Mb | 260 | 560 | 300 | 244 | 544 | 26 | 2 | 10 |
| MAASTR. | Boesdal/Hansa Mb | 560 | 675 | 115 | 544 | 659 | 20 | 0.5 | 2.5 |
| CAMP. | Flagbanke Mb | 675 | 730 | 55 | 659 | 714 | 18 | 0.5 | 2.5 |
| Cret. | Lower Chalk Unit | 730 | 1200 | 470 | 714 | 1184 | 18 | 0.5 | 2.5 |

| **Vest-** | | Temperature | Thermal | vol.Heat | Rock |
|---|---|---|---|---|---|
| **forbrænding** | **PROGNOSIS,** | mid unit (*) | cond. | capacity | density |
| Glostrup, Ejby | **Cont.** | deg.C | (W/m/K) | (MJ/m3/K) | (g/cc) |
| Quaternary | Quaternary undiff | 8.1 | 2 | unknown | 2.5 |
| DANIAN | København lst. | 8.3 | N/A | N/A | N/A |
| DANIAN | Bryozoan lst. | 8.7 | 1.69 | 2.9 | 2.6 |
| MAASTR. | Sigerslev Mb | 10.8 | 1.78 | 2.8 | 2.7 |
| MAASTR. | Rørdal Mb | 13.2 | 1.98 | 2.7 | 2.7 |
| MAASTR. | Hvidskud Mb | 17.0 | 2.08 | 2.6 | 2.7 |
| MAASTR. | Boesdal/Hansa Mb | 21.6 | 2.31 | 2.5 | 2.7 |
| CAMP. | Flagbanke Mb | 23.5 | 2.39 | 2.4 | 2.7 |
| Cret. | Lower Chalk Unit | 29.2 | | | |

(*) The temperature data listed in the well prognosis are based on an average temperature gradient of 22°C/km.

According to Japsen (1998), the Chalk Group experienced structural uplift in Neogene times, leading to creation of some fractures. Based on experiences from North Sea chalk and due to the uplift of the chalk within the Copenhagen area, the effective permeability is assumed to be about 5 times higher than the matrix permeability (Table 2), primarily due to fracture presence.

## 4.1 Reservoir simulation model for the Vestforbrænding site

GEUS conducted a number of reservoir simulations aiming at estimating volumes, potential production and injection rates together with an expected pressure and temperature development. The design and properties of the base case model utilized the geological well prognosis for the Vestforbrænding site and is described below.

The geometry of the base case model builds on a gross area of 12 km x 12 km around the Vestforbrænding site – and vertically, the model is delineated by the tops and thicknesses listed in Table 2. The well configuration includes two vertical wells (HTES-1 and HTES-2) with a distance of 1 km. A lateral coarse grid of 200m x 200m is used globally, but the coarse grid has been refined around the wells: locally at wells 50m x 50m and very close to wells 10m x 10m. In the vertical direction the grid dimension ranges from 2 m to 40 m, with the finest grid size in the reservoir interval. With respect to reservoir properties, the permeabilities and porosities outlined in Table 2 are transferred to the simulation model, and used as input data. Information about thermal conductivities and heat capacities for chalks and limestones are obtained from Balling et al. (1981), cf. Table 2.

The presumed charging period is May–mid October. Formation water is extracted from a '**Cold Well**' (HTES-1) and then the water is heated up to 90℃ by means of excess heat and finally, the water is injected into the storage zone using another well that herein is named the '**Warm Well'** (HTES-2).

An intermission period of 14 days is introduced, and this period is considered sufficient for converting the wells from production to injection mode – and vice versa.

The presumed extraction period is November–mid April: The HTES-2 well is now converted into a production well. Accordingly, the stored and warm water is produced from HTES-2 and next, the energy is extracted using a heat exchanger that heats the circulating water of the district heating system. After passing the heat exchanger, the expected temperature of the cooled formation water is in the temperature range 20–40℃ (20℃ in case 1 and 40℃ in case 2). The cooled formation water is then re-injected into the subsurface using the HTES-1 well. In this way, the water in the system circulates and no extra water is needed.

Model set-up: The 'Warm Well' produces pre-heated, hot water from the storage zone, with an applied bottom hole pressure of 3 bar (drawdown constraint). The injection rate is controlled by a full voidage constraint, meaning that the produced and injected volumes are identical at reservoir conditions. With respect to both HTES-1 and HTES-2, the completion length is 400 m in the base case model, i.e. the well is fully open to the reservoir in the interval 400–800 m.

In the base case simulations, GEUS consider unstimulated wells drilled into the presumed storage reservoir in the chalk. Using the above parameters, the base case simulations point to an average injection rate of *c.* 600 $m^3$/day (~25 $m^3$/h), when the Warm Well (HTES-2) is in charge mode, and an average production rate of *c.* 800 $m^3$/day (~35 $m^3$/h), when the well is in production mode. Production and injection cycles in the HTES-2 well is illustrated in **Figure 3** during a four year period (2021–2025). The difference in rates for the production/injection mode for the well is caused by the viscosity dependency of temperature on the formation water. In charge mode (injection) the HTES-2 well is dependent on the volume of water that can be produced from the HTES-1 well (Cold Well). This situation is constrained by the maximum drawdown in the well and the fact that cold formation water is more difficult to produce than pre-heated formation water. In the reverse situation, when hot formation water is produced from the HTES-2 well, the cooled formation water is injected into the reservoir using the HTES-1 well, and in this case a relatively high injection pressure can be applied. The only constraint to the injection pressure is the formation fracture pressure (and pump efficiency).

The results of the reservoir simulations are summarised in Table 3. It appears from the table that the 'Mid case–High case' and the 'Low case–Mid case' ranges are quite large, signifying considerable uncertainties.  When dealing with potential flow rates, the **most critical parameter is the effective permeability ($K_{eff}$).** Note that the rates listed below are based on production from one well only. The low, base and high case scenarios presumes 2½, 5 and 25 times higher permeability than the matrix permeability ($K_{matrix}$). The effective permeability is greater than the matrix permeability, primarily due to the presence of fractures in the chalk.

In addition, GEUS simulated potential production rates based on a well stimulation technique that includes completion with 8 or 16 artificial and sand-propped fractures. The distance between fractures is 50 m and 25 m, respectively. A well stimulation strategy based on intensive fracturing of an area close to the well bore (i.e. 100 m around the well) point to high production rates. The use of deviated wells will also lead to higher production rates compared to the base case scenario. Similar scenarios are set up and completed with respect to simulation of injection rates.

**Table 3: Simulation cases**

| **Simulation case *)** | **Effective perm.** | **Prod. Rate ($m^3$/day)** | **Prod. Rate ($m^3$/h)** |
|---|---|---|---|
| Base case | $K_{eff} = 5 \cdot K_{matrix}$ | 800 | 35 |
| Low case | $K_{eff} = 2½ \cdot K_{matrix}$ | 360 | 15 |
| High case | $K_{eff} = 25 \cdot K_{matrix}$ | 2160 | 90 |
| Well stimulation, 8 fractures | $K_{eff} = 5 \cdot K_{matrix}$; 50m between fracs. | 1200 | 50 |
| Well stimulation, 16 fractures | $K_{eff} = 5 \cdot K_{matrix}$; 25m between fracs | 1680 | 70 |
| Well stimulation: 100 m around well | $K_{eff} = 5 \cdot K_{matrix}$; Well stimulation close to the well bore and $K_{eff} = 10 \cdot K_{matrix}$ | 3000 | 125 |
| Deviated wells | 30 deg. dev in res. sec. & $K_{eff} = 5 \cdot K_{matrix}$ | 1080 | 45 |

*) For the different simulation cases, the estimated heat return (efficiency) is in the range 75–85%.

Flow rates, which are significantly higher than the base case rate, may be obtained if:

- The storage system is based on an array of wells – and not just one well. A multi-well storage system will definitely increase the productivity considerably.
- Very long completion lengths are used (pumping intervals > e.g. 400m).
- Reservoir treatment is implemented, aiming at increasing the effective permeability, e.g. intensive fracturing of the chalk, acid stimulation, hydro-fracturing, application of fish-bone or jetting techniques or other methods.
- The storage system is based on one and possibly shorter production well (e.g. 500 m) combined with one or two injection wells. The injection well(s) should be rather long and preferably also deviated.
- The pilot well is placed in an area with several fault-induced fractures.
- The storage system is based on horizontal or highly deviated wells.

The Vestforbrænding site is considered a high-risk ‘prospect’, as the matrix permeability is low and the effective permeability is not known. In addition, the distance to the nearest deep well (Margretheholm-1) is more than 10 km. Prior to drilling, further evaluation of the ‘prospect’ is recommended. This evaluation may include calculations on the effect of well stimulation and on the effect of loading the aquifer with hot water during the summer period and unloading during winter. Focus should be on one of the best reservoir zones, i.e. the Hvidskud Member, alternatively the Sigerslev Member. Despite further investigations, it may turn out that drilling and coring is the best way to test and evaluate the ‘prospect’. A flow test is also definitively needed.

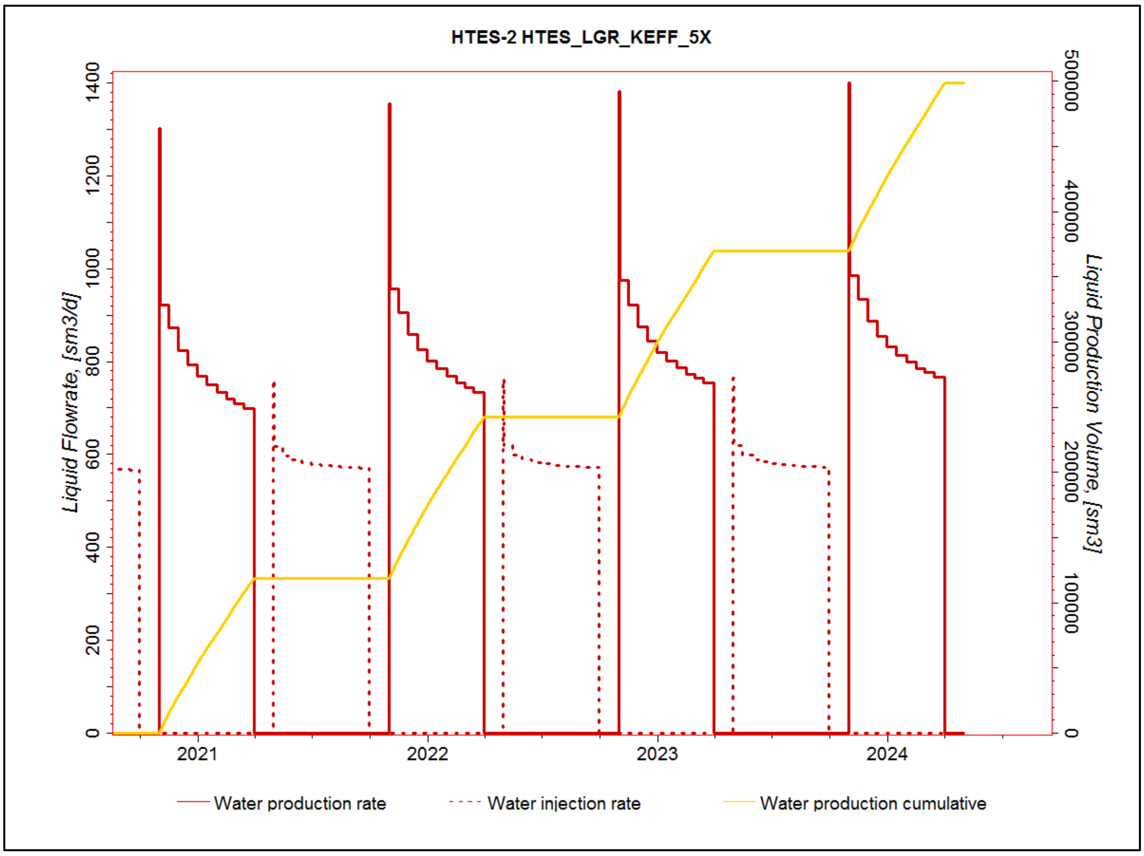



**Figure 3**: *Modelled production/injection cycles in the HTES-2 well (‘Warm Well’), years 2021–2025. Observe that the simulated water production rate decreases during an extraction period, as the pre-heated water tends to loose less energy close to the well bore.  During the 4 years period, there is a slight increase in both the production and injection rates, as the overall temperature in the storage zone slightly increases, leading to lower viscosity of the water.*

# 5. Conceptual model for presumed faulted/fractured sites ('prospects')

The 'prospects' are associated with areas affected by intensive faulting, creating fractures in the chalk. These areas correspond to the presumed faulted and fractured sites related to the prominent Amager, Carlsberg and Øresund fault systems. These fault systems consist of a series of faults and not just one major fault plane. Hydrogeological investigations of the chalk and limestones in the Copenhagen area have shown that especially the Carlsberg Fault zone is associated with a general increase in permeability and hydraulic conductivity.

One particular 'prospect' is considered in the following text, specifically the faulted site at line HGS-001; see **Figure 2** for location. The figure also points out pronounced fault zones and it provides an overview of the pre-Quaternary strata. The structural position of the formation tops related to this 'prospect' is someplace between the Vestforbrænding and Margretheholm tops. As an approximation, surface depths are calculated as averages of the formation tops at the two localities Vestforbrænding and Margretheholm. The storage interval encompasses the Hvidskud, Boesdal and Flagbanke Members, and the storage zone consists most likely of heterogeneous chalk characterised by many fractures that have different apertures (fracture width). Occasionally, intervals with crushed chalk will probably be present and presumably, the crushed chalk reflects intense faulting of the chalk section.

A general geological well prognosis accompanied by reservoir parameters is tabulated below (Table 4). The temperature data are based on an average temperature gradient of 22°C/km. The table lists a range with respect to effective permeabilities, as the prediction of permeability in this faulted area is associated with large uncertainty. In fact, no information about the reservoir permeability exists in the GEUS database, when dealing with the depth range 400–800 m (i.e. the planned storage depth). Occasionally, effective permeabilities up to 100 mD may occur in the aquifer, but GEUS cannot guarantee that such high permeabilities are generally applicable to the chalk reservoir at this site. The permeability estimate of 100 mD is in line with the average permeability of the fractured Bryozoan limestone in the greater Copenhagen area.

This conceptual HGS-001 model may be representative of almost all faulted and fractured sites related to the Amager, Carlsberg and Øresund fault systems. The Amager and Carlsberg Faults are identical when dealing with the Amager Island. The parameters listed in Table 4 (including tops) are to be adjusted, once considering a particular site within these faulted areas. GEUS finds that especially the Carlsberg Fault zone is relevant when considering thermal storage.

Not only the HGS-001 site ('prospect') described above, but in fact all sites related to highly faulted zones are considered high-risk 'prospects' as the degree of fracturing is difficult to address, meaning that the effective permeability estimates listed in the table are very uncertain. The effective permeability assessments are therefore only rough estimates as described above. Furthermore, the extension of the fractured areas cannot be mapped in detail due the limited resolution of the seismic 2D data. In addition, a fault plane may act as a pathway for transporting the water away from the storage site.

- A fault may provide a connection between the upper fresh water resources and deeper salt water, and injection and pumping at deeper levels most likely affects the present groundwater resources and the surface environment. Such a situation is particularly problematic in water protection areas and nature protection areas (Natura 2000). Blem (2002) modelled the effects of pumping from the upper part of the Carlsberg fault, and he found that lowering of the water table primarily propagates along the fault zone. In this shallow setup inflow of water from the harbour also appears to take place. In order to progress, GEUS recommends to carry out more detailed modelling of the hydrology of the Carlsberg fault zone – and faulted zones in general.

- GEUS recommends investigating the areas affected by intensive faulting in further detail, aiming at improving the geological model – and with the objective to reduce the geological uncertainty and the uncertainty connected to the assessment of reservoir properties (Table 4). Especially extra work that can help in decreasing the uncertainty related to the reservoir permeability is essential. The fluid flow pattern related to fractures and fault planes should also be investigated.

- The areas with presumed enhanced permeability are difficult to identify, as the exact locations of the faulted areas are difficult to identify. Each major fault system most likely consists of a series of minor faults. Prior to drilling, additional mapping and further examination on the location of the fault planes is recommended. Especially the fan shooting method appears to be an effective way to map the trace of fault zones in densely urbanized areas (Nielsen et al. 2005). GEUS also recommends to utilize these authors' work on mapping of the Carlsberg Fault in the present study.

- Despite further investigations, it may turn out that drilling and coring is the only practicable way to test and evaluate the 'prospect'.

**Table 4: Well prognosis for the HGS-001 faulted zone site**

For location, see Fig. 2

| **Locality:** | -at line HGS-001 | Top | Base | Thick | Top | Base | Porosity | matrix | Effective |
|---|---|---|---|---|---|---|---|---|---|
| **Fault zone** | **PROGNOSIS** | (mMD) | mMD | (m) | b.MSL | b.MSL | (%) | Permeabiliy (mD) | |
| Quaternary | Quaternary undiff | 0 | 16 | 16 | -16 | 0 | N/A | N/A | N/A |
| DANIAN | København lst. | 16 | 36 | 20 | 0 | 20 | N/A | N/A | N/A |
| DANIAN | Bryozoan lst. | 36 | 84 | 48 | 20 | 68 | 38 | 30 | 100 |
| MAASTR. | Sigerslev Mb | 84 | 194 | 110 | 68 | 178 | 35 | 3 | 5 – 100 |
| MAASTR. | Rørdal Mb | 194 | 278 | 84 | 178 | 262 | 29 | 2 | 5 – 100 |
| MAASTR. | Hvidskud Mb | 278 | 565 | 287 | 262 | 549 | 26 | 2 | 5 – 100 |
| MAASTR. | Boesdal/Hansa Mb | 565 | 710 | 145 | 549 | 694 | 20 | 0.5 | 1 – 15 |
| CAMP. | Flagbanke Mb | 710 | 763 | 53 | 694 | 747 | 18 | 0.5 | 1 – 15 |
| Cret. | Lower Chalk Unit | 763 | 1400 | 637 | 747 | 1384 | | | |

| **Locality:** | -at line HGS-001 | Temperature | Thermal | vol.Heat | Rock |
|---|---|---|---|---|---|
| **Fault zone** | **PROGNOSIS,** | mid unit (*) | cond. | capacity | density |
| **Copenhagen** | **cont.** | deg.C | (W/m/K) | (MJ/m3/K) | (g/cc) |
| Quaternary | Quaternary undiff | 8.2 | 2 | unknown | 2.5 |
| DANIAN | København lst. | 8.6 | N/A | N/A | N/A |
| DANIAN | Bryozoan lst. | 9.3 | 1.69 | 2.9 | 2.6 |
| MAASTR. | Sigerslev Mb | 11.1 | 1.78 | 2.8 | 2.7 |
| MAASTR. | Rørdal Mb | 13.2 | 1.98 | 2.7 | 2.7 |
| MAASTR. | Hvidskud Mb | 17.3 | 2.08 | 2.6 | 2.7 |
| MAASTR. | Boesdal/Hansa Mb | 22.0 | 2.31 | 2.5 | 2.7 |
| CAMP. | Flagbanke Mb | 24.2 | 2.39 | 2.4 | 2.7 |
| Cret. | Lower Chalk Unit | 31.8 | | | |

(*) The temperature data listed in the well prognosis are based on an average temperature gradient of 22°C/km, and the predicted formation temperatures are calculated as follows: Temperature (on avg.) = 8°C + 22°C/km x Depth[km].

# 6. Geochemical reactions / carbonate precipitation

Operating the heat storage involves cyclic heating and cooling of the chalk aquifer. Laboratory experiments on chalk samples suggest that the mechanical strength of the chalk reservoir rock decreases as consequence of repeated heating and cooling (Voake et al., in prep.). GEUS recommends conducting additional geotechnical testing of the reservoir chalk, both in-situ and in the laboratory.

Periodical heating of groundwater (formation brine), along with injection and storage in a chalk aquifer, may also lead to geochemical reactions in the rock-water system. Calcite is likely to precipitate due to heating of groundwater during the cycles of aquifer thermal energy storage. Therefore, water treatment is most likely needed, e.g. ion exchange or addition of acid, in order to prevent clogging of the heating facilities including the injection well (Sanner, 1999). The exact composition of the precipitate may differ from that of pure calcite due to the presence of cations such as iron, magnesium and manganese. Furthermore, the exact environment of precipitate formation is difficult to judge from thermodynamic consideration alone (Griffeoen & Appelo 1993). Therefore, investigations related to the specific location of the HTES plant, groundwater chemistry and aquifer type would be needed in order to prevent clogging, carbonate precipitation and mineral deposition (scaling) at the Copenhagen site.

The challenge is to design an optimal water treatment procedure that can handle the circulating water before it enters the heat exchanger, i.e. a pre-processing unit should be added to the system. The overall objective is removal of cations, but also particle removal is essential. GEUS recommends considering application of advanced filter technology, use of ion exchangers, addition of acids to lower pH, and addition of scaling inhibitors. Furthermore, the HTES system should be kept pressurized to prevent degassing. The final design of an appropriate water treatment programme is to be set up in a subsequent Phase 2; detailed information about the composition of the formation brine is needed prior to designing the water treatment programme.

# 7. General recommendations

In the view of GEUS and based on the presently available data, the potential storage sites identified so far are high-risk 'prospects'. Moreover, it is not possible to identify well-defined target locations representing the best production zones (conventional sweet spots). Alternatively, potential drilling sites may be pinpointed from the location of existing infrastructure facilities or from the position of the structural elements. If the unconventional "sweet spots" described in paragraphs 4 and 5 still are positively assessed with respect to risks, volumes and economical aspects, **GEUS thus recommends a series of de-risking activities, including drilling a pilot well prior** to establishing a storage system in the chalk section. **GEUS recommends to core, log and flow test the well** with the objective to achieve additional information about chalk productivity, reservoir properties, geological and geotechnical parameters. It is recommended to focus on determining the effective permeability, fracture presence and reservoir parameters in general, but focus should also be on evaluating the elastic moduli, stiffness and strength of the reservoir chalk. A core from the storage zone is needed for more accurate assessments of the matrix permeability and the geotechnical properties of the chalk.

GEUS recommends to base the storage design on a chalk cylinder combined with an array of wells (multi-well system). GEUS recommends applying well stimulation for enhancing the natural permeability and thereby increase the effective permeability. Well stimulation may include activities such as acid stimulation, high energy stimulation and/or hydro-fracturing. The latter methodology is described in detail in Smith (1989) and in Comeskey & Smith (2016). The purpose of applying well stimulation is to ensure and maintain reasonably high production/injection rates in a low permeability chalk reservoir.

GEUS recommends using water treatment in order to handle clogging, scaling and corrosion processes in the chalk-water system. The challenge is to design an optimal water treatment procedure that can handle the circulating water before it enters the heat exchanger, i.e. a pre-processing unit should be added to the system. GEUS suggests to consider ion exchange, lowing of pH and to make use of filters (cation and particle filters).

GEUS has considered two types of prospects: (i) matrix types like Vestforbrænding and (ii) prospects located close to a fault zone. GEUS recommends placing a coming thermal storage outside fault zones, because there is a risk that the injected water gets into contact with large volumes of cold sediment, and withdrawal of hot water may, therefore, not be possible.

# 8. FeFlow and Eclipse modelling

The planned storage depth (400–800 m) implies that interaction between the storage and groundwater zones may occur. Numerical groundwater and reservoir models are established, therefore, with the objective to simulate the storage potential, water flow rates, pressures and temperatures in the depth range 0–1000 m. Both the groundwater and storages zones are included in the model-simulation in order to uncover possible effects on the groundwater system. It is very difficult to set up a single, trustworthy full-scale model that describes the heat and water transport in the chalk section. So alternatively, GEUS has set up a number of conceptual models with varying complexity (see below).

The objectives of the computer simulations are to model heat and water transport, and to estimate potential production rates. Our modelling runs point to rather low rates, unless specific well configurations are used and/or well stimulation is applied. So far, GEUS has constructed five conceptual models, and a number of water injection and withdrawal scenarios are simulated. The presumed interaction between storage and groundwater zones is also considered. Most likely, the chalk package in between the groundwater and storage zones acts a sort of seal that prevents upward fluid flow (but not pressure propagation). In reality, this interval does not form a complete seal, because the chalk is not impermeable.

The five conceptual models are:

1. A homogeneous model. Input parameters are based on the geological well prognosis for the Vestforbrænding site.
2. A stimulated model/heterogeneous model. The model consists of a cylinder of chalk that has been stimulated, assuming a permeability of 20 mD. The surrounding chalk is expected to be homogeneous (with a permeability of 2 mD).
3. A layered model. Each section consists of a 90 m thick chalk layer with permeability of 2mD followed by 10 metres of fractured chalk with a permeability of c. 180 mD.
4. A stimulated well model. A cylinder of chalk is considered, the permeability of the chalk inside the cylinder varies between 2 and 38 mD.
5. A model where the well is placed in a fault zone.

Identical scenarios for heat storage are simulated with FeFlow and Eclipse to compare and evaluate the performance of the two software packages. The storage potential, heat transport, water transport, flow rates, pressures and temperatures are considered. The FeFlow software package is from DHI-WASY GmbH and Eclipse software package is from Schlumberger.

The FeFlow and Eclipse simulations point to comparable and rather similar results with respect to flow rates, heat transport, pressure development and temperature profile. These comparable simulation results means that both software packages can be used for analyzing and describing the reservoir performance in the depth range 0–800 m.

# 9. Conclusions

GEUS has assessed the storage potential of the chalk in the greater Copenhagen area. The evaluation of the existing data material led to the following conclusions on the target zone and the expected reservoir performance**:**

1. The porosity of the chalk at Copenhagen is well-known, e.g. from interpretation of well-logs.
2. For the time being, the database with reservoir-geological data is sparse and the existing geological model should therefore be updated as soon as new data become available. No direct permeability measurements are currently available from the chalk in the storage zone, but the GEUS evaluation of the existing data material points to a matrix permeability of 2 mD and an effective permeability that is 5 times higher than the matrix permeability.
3. The GEUS investigations signify that the chalk section can be used for heat storage, but potential water production rates are difficult to assess. To address rates, GEUS conducted reservoir simulation studies based on the current geological model and our present-day knowledge on reservoir parameters. The GEUS base case simulations point to an average injection rate of *c.* 600 $m^3$/day (~25 $m^3$/h) and an average flow rate of *c.* 800 $m^3$/day (~35 $m^3$/h) per well, when considering a 4 year production/injection period.
4. The water injection leads to increased pressure in the storage zone. The reservoir simulations carried by GEUS indicate that this pressure disturbance affects the formation pressure at the base of the groundwater zone, but only to a limited extent (i.e. <1 bar due to the full voidage replacement constraint). Conversely, the fluid flow in the storage zone does not interact with the groundwater zone. In the view of GEUS, a thermal storage can be established in the chalk section and a potential conflict between storage and groundwater interests is not foreseen.
5. No geotechnical tests/data are available from the storage zone, meaning that the elastic moduli, stiffness and strength of the chalk are not known. These parameters are critical for deciding on an appropriate production technology, e.g. well stimulation.
6. No production tests or well tests are presently available from the chalk section in the depth interval 400–800 m, meaning that the productivity (and effective permeability) of the chalk in the storage zone is not known. With respect to determining pertinent reservoir parameters, is will be essential to conduct a production test to assess chalk productivity.
7. GEUS considered two prospect types having storage potential: (i) a matrix type like Vestforbrænding and (ii) a prospect located close to a fault zone. Especially the latter prospect type is associated with high risks and problems related to withdrawal of hot water and loss of injection water. With respect to favored storage site, a location outside faulted zones is preferred to a fault zone location.
8. GEUS carried out a number of reservoir simulations, including sensitivity studies on potential production rates. These studies are based on various permeability assessments and the use of different well stimulation techniques.
9. In order to de-risk a preferred prospect and the concept of using chalk for thermal storage, GEUS suggests a series of de-risking activities, such as improved prospect evaluation, drilling a pilot well and comprehensive data acquisition prior to establishing a thermal storage plant. GEUS recommends to core, log and flow test the well with the objective to achieve additional information about chalk productivity, fracture presence, reservoir parameters and the geological aspects of the chalk in the storage zone.

# 10. Suggestions for Phase-2 work

The existing knowledge on the reservoir parameters of the chalk in the storage zone is limited. GEUS recommends, therefore, to acquire more accurate and thorough data during a Phase-2 working period. With respect to Phase-2 work, GEUS suggests to:

- Drill a pilot well into the storage zone. The well drilling process should be accompanied by data acquisition: testing, coring, and logging.
- Analyze and describe the cores cut in the pilot well: Measure porosity, permeability, fractures and geotechnical parameters, make core flooding experiments etc.
- Evaluate the well test data and the acquired logs from the pilot well to point out the best layers for thermal storage. The results of the core analyses, well test interpretation and the log interpretation will positively assist in the decision making on storage design etc.
- Test if the chalk is an appropriate storage media. Examine how the chalk reacts to water injection and withdrawal.
- GEUS suggests the use of water treatment in order to handle clogging, scaling and corrosion processes in the chalk-water system. This water treatment may include the use of ion exchange, acids and filters (for cations and particle removal).
- Collection of a water sample from the target zone for geochemical analysis etc.
- Examining the possibilities of applying well stimulation – and apply well stimulation, if appropriate.
- Set up of a full-scale (full-field) reservoir simulation model. The main purpose is to history match of the production test data. Furthermore, the effects of long-term production can be predicted.

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# 1 Work Package 3: Business Case Models

## 1.1 Introduction

This chapter presents the underlying work and results of business case models of heat storage and recovery in chalk reservoirs. Numerical models of reservoir flow and heat transport developed based upon the reservoir conceptual models presented in Work Package 1, were constructed and run to generate 30-year heat energy production profiles for Low Case, Best-Technical Estimate and High Case scenarios. The heat energy production profiles were used calculate the heat energy lost to the subsurface and define the revenue in the cash flow models. Work presented in appendix 1 and 3 was used to define the construction and operating costs of the wells and facilities in the business case models.

## 1.2 Reservoir Conceptual Models

Conceptual models of the chalk reservoirs in the greater Copenhagen area were developed in Work Package 1 of the HTES project and are presented in appendix 4 and 5. The flow units and hydraulic properties of the chalk reservoir conceptual models are based upon the petrophysical interpretation of the Vesterforbrænding well and the porosity-permeability relationship by GEUS. The reservoir conceptual models were used to define the reservoir geometry, flow properties, thermal properties and initial reservoir conditions in Low Case, Best-Technical Estimate (BTE) and High Case flow and heat transport models, which in turn, were used to generate heat energy production profiles for the business case models.

### 1.2.1 HTES Concept

The concept underlying the HTES project is that excess heat energy generated by industry during the Summer is used to heat up water that is injected into chalk reservoirs at depths of 300 to 800 meters below ground surface (mbgs). The hot water stored in the chalk reservoir is back-produced during the Winter heating season and used to supplement the base load demands of district heating systems.

In its simplest form, a HTES system consists of two wells:

1. A dedicated production well that only operates during the Summer and produces cold saline water from the chalk reservoir. The cold water is pumped to the surface and heated with excess industrial thermal energy using a heat exchanger.
2. An injection/production well used during the Summer months for injecting the hot water carrying the excess industrial heat into the chalk reservoir. During the winter months the well functions as a production well and back-produces the hot water injected during the Summer for use in district heating systems.

### 1.2.2 Numerical Flow and Heat Transport Models

Numerical models of flow and heat transport in the chalk reservoirs were developed with the primary objectives of:

- Quantifying the range of production rates for a single well completed in the chalk
- Quantifying the range of the recovery efficiency of wells injecting and back-producing hot water
- Generating a range of thermal energy production profiles for use in the business case models.

The flow and heat transport models were run using the Rubis software from Kappa Engineering. The model domain is circular with a 5000-meter radius and has a single well located in the centre of the model. The reservoir models consist of four flow units, each of which has a constant thickness and porosity. Cross-sections are presented Figure 1 that show the porosity, permeability and screen lengths assigned to the Low Case, Best-Technical and High Case models.

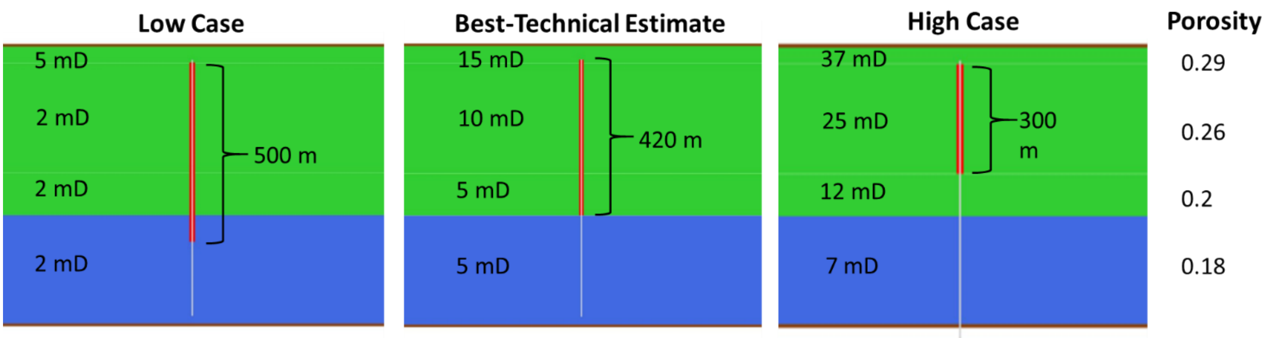


Figure 1. Cross-sections through the Low Case, Best-Technical Estimate and High Case numerical flow and heat transport models showing the permeability, porosity and screen lengths (depicted in red).

The production constraints used in generating the thermal heat energy production profiles are presented in Table 1. The drawdown in the production wells is constrained by the depth of the submersible pump, which is assumed to be placed at 320 meters below ground surface (mbgs). Simulations were performed with injection temperatures of 80 and 90 °C. For the 80 °C injection scenario, it is assumed that the surface facilities include a heat pump, which allows for the reduction of the outlet water temperature to 20 °C. The annual injection and production cycle consists of 5.5 months of hot water injection during the Summer, a 0.5 month shut-in of the well(s), 5.5 months of hot water production during the Winter heating season and a 0.5 month shut-in of the well(s).

Table 1. Operational constraints used in the flow and heat transport models.

| Operational Constraints | Value |
|---|---|
| Maximum Drawdown (bars) | 30 |

| | |
|---|---|
| Temperature of injected water (deg C) | 90 (80*) |
| Temperature of outlet water (deg C) | 35 |
| Temperature of outlet water with heat pump (deg C) | 20 |
| Duration of injection period (months) | 5.5 |
| Duration of soak period (months) | 0.5 |
| Duration of production period (months) | 5.5 |
| Duration of soak period (months) | 0.5 |

*includes a heat pump*

### 1.2.3 Screen lengths and production rates

The Low Case, BTE and High Case flow models were run with the objectives of optimizing the screen lengths in the injection/production well and estimating the flow rates of a single well in each model. The models were run with a single well producing for a 1-year period with a drawdown constraint of 30 bars (assumes a pump depth of 320 m below groundsurface). The top of the well screen was set at 250 mbgs and the screen length was adjusted manually using trial-and-error until the drawdown constraint was honoured. The resulting screen lengths and production rates (Table s) were used in simulations to quantify the thermal energy production from a single well in each model (low case, BTE and high case) and to determine the well count for the business case models. It is assumed that the wells in the Low Case and Best-Technical Estimate models are stimulated in order to improve the production capacity of the wells due to the relatively low reservoir permeability in these models.

Table 2. The screen lengths and production rates in the low case, BTE and high case flow models.

| Flow Model | Screens Lengths (m) | Production rate ($m^3$/hr) |
|---|---|---|
| Low Case | 500 | 20 |
| Best-Technical Estimate | 420 | 50 |
| High Case | 300 | 150 |

### 1.2.4 Thermal energy production per well

The thermal energy production from a single injection/production well in a chalk reservoir was estimated using the Low Case, BTE and High Case flow models. The well was operated on the annual injection/production cycle shown in Table 1 and with an injection temperature of 90 $^oC$. The models were run for 30 years using the screen lengths and injection/production rates in Table 2. The thermal energy production in MW was then calculated using the production rate, the simulated temperature of the produced water at the surface and the specific heat capacity of the reservoir brine.

Profiles of the simulated surface temperature of the produced water from the BTE model during the Winter heating season are presented in Figure 2 for years 1, 5, 10, 20 and 30. The surface temperature of the produced water is below the injection temperature of 90 °C for all the years presented. This is due to the loss of heat from the well to the subsurface as the hot water flows from the reservoir to the surface. During each production period, the temperature of the produced water decreases due to heat loss to the reservoir. As the number of injection/production cycles increases, the reservoir heats up and heat loss to the subsurface becomes less as reflected by the increase in the temperature production profiles over time. For example, during year 1 the temperature of the produced water decreases markedly from about 87 °C at the beginning of the production cycle to about 43 °C at the end of the production cycle (5.5 months). The temperature of the produced water is greater than 60 °C by the end of year 10 (10 injection/production cycles), and by year 30 the temperature of the produced water is greater than 70 °C throughout almost the entire production period (heating season). This is also illustrated in Figure 3, which shows the average temperature of the simulated water produced at the surface for years 1, 5, 10, 20 and 30. The average surface temperature of the produced water is 62, 74 and 77 °C for years 1, 10 and 30, respectively. The amount of heat energy produced relative to the amount of heat energy injected increases with time from 68, 82 and 86% for years 1, 10 and 30, respectively. Conversely, the simulated heat loss to reservoir is about 32% for the first year of production and decreases to 14% by year 30.

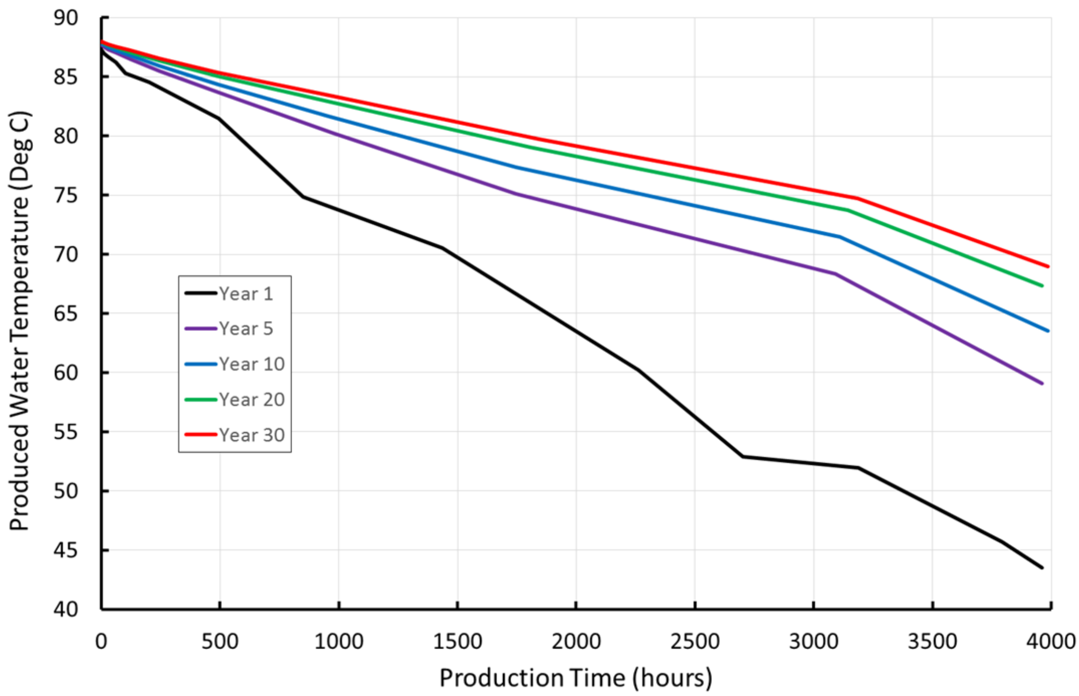


Figure 2. The simulated surface temperature of the produced water over a production period and for different years.

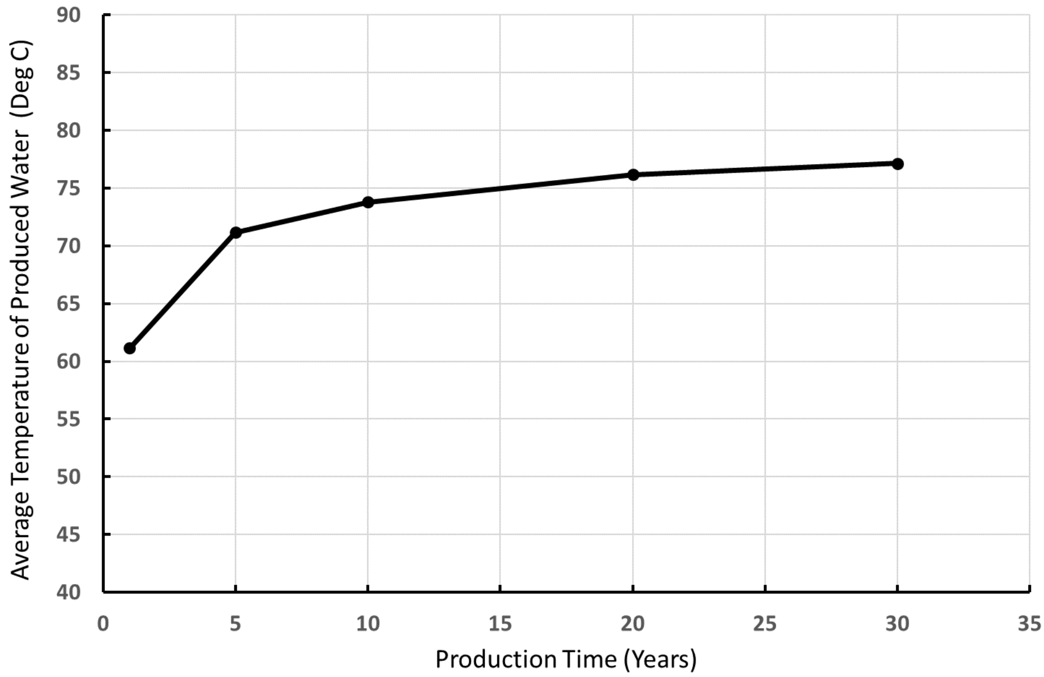


Figure 3. The average temperature of the produced water at the surface from the BTE model (injection temperature is 90 $^oC$).

The simulated energy production (MW) over a 30-year period from a single well in the Low Case, Best-Technical Estimate and High Case models is presented in Figure 4. Common to all three of the models is that the simulated energy production increases with time as the reservoir heats up and the energy loss to the subsurface decreases. The large contrast in the simulated energy production between the Low and High Case models is directly related to the differences in reservoir permeability, which controls the volume of hot water (thermal energy) that a given well is capable of injecting into and back-producing from the reservoir.

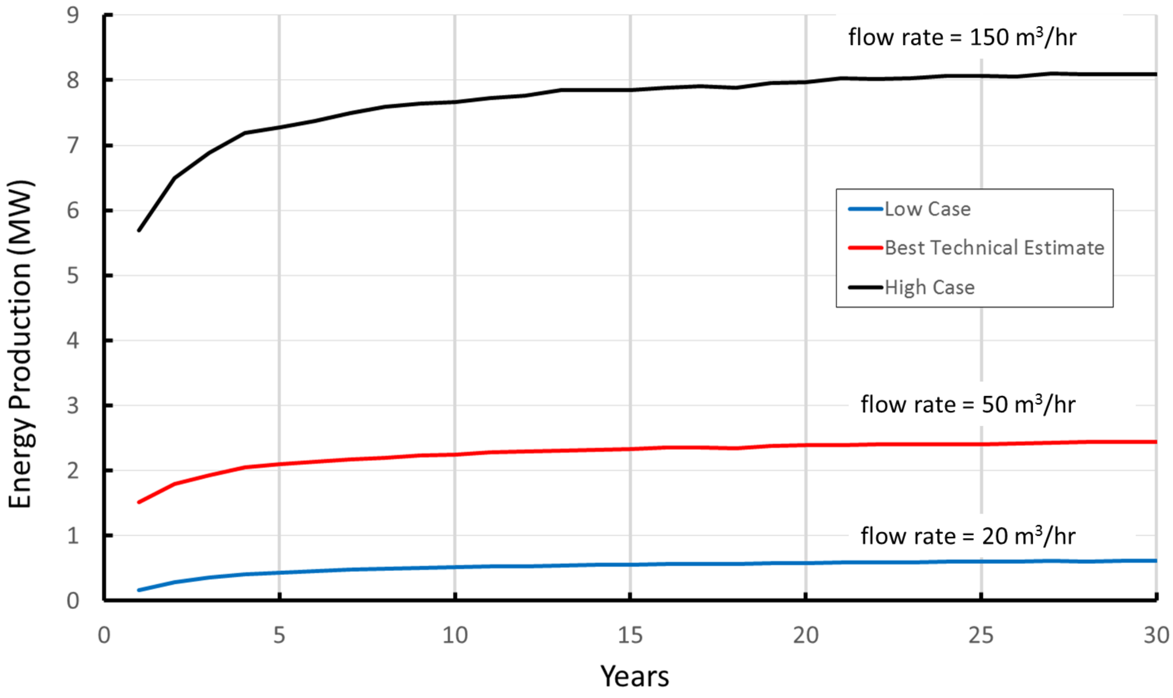


Figure 4. Energy production profiles for a single injection/production well in the Low Case, Best-Technical Estimate and High Case models.

## 1.3 Business Case Models

The business cases for the thermal energy storage and recovery models were calculated using a cash flow model. Input to the business case models includes:

- 30-year thermal energy production profiles
- Well design, count, drilling, construction and cost
- Facilities design and cost
- Financing
- Facilities and wells operating costs.

### 1.3.1 Wells

The business case models were run with a target flow rate of 150 $m^3$/hour. The results of the single wells simulations (presented above) were used to determine the number of wells (well count) needed in the business case models to achieve the target flow rate of 150 $m^3$/hour. The well count was used in determining the cost of drilling, completing and stimulating (Low Case and BTE models) the wells and operational/maintenance costs. Details of the wells that were used in the business case models are summarized in Table 3.

Table 3. Well information used in the business case models.

| | Low Case | Best-technical Estimate | High Case |
|---|---|---|---|
| Completion Length (m) | 500 | 420 | 300 |
| Stimulation | Yes | Yes | No |
| Flow rate per well ($m^3$/hr) | 20 | 50 | 150 |
| Cold water production wells | 8 | 3 | 1 |
| Hot water injection/production wells | 8 | 3 | 1 |
| Total Well Count** | 16 | 6 | 2 |
| Total Flow Rate ($m^3$/hr) | 160 | 150 | 150 |
| Cost (million Dkk) | 95 | 25 | 7.2 |

*number of hot water injection/production wells needed to meet the target of produce 150 $m^3$/hour
**sum of the cold water production wells and hot water injection/production wells

### 1.3.2 Thermal Energy Production Profiles

The thermal energy production profiles used to define the revenue in the business case models were calculated using the energy production profiles from the single well Low Case, BTE and High Case models (Figure 4) and the number of injection/production wells needed to obtain the target facilities flow rate of 150 m3/hour (Table 3). For example, a single well in the BTE model produces 50 $m^3$/hour given the production constraints presented in Table 1, and therefore, three injection/production wells are required to produce the target rate of 150 $m^3$/hour. The thermal energy production profile used in the BTE business model was calculated by multiplying the energy production profile for a single well in the BTE model (Figure single well produced energy) by three. For the Low Case, the thermal energy production profile used in the business case model was obtained by multiplying the single well production profile for the Low Case model (Figure 4) by eight. In the High Case model, a single well is capable of producing 150 $m^3$/hour, so the energy production profile presented in Figure 4 was used directly as the thermal energy production profile in the business case. The Low Case, BTE and High Case thermal energy production profiles used in the business case are presented in Figure 5. The thermal energy production profiles in MW hours (Figure 6) was calculated by multiplying the thermal energy production profiles in MW by the number of hours in the Winter heating season production period (3960 hours). The revenue in the business case models was calculated using the production profiles presented in Figure and an assumed a heat price of 410 Dkk/MWh, which is the 2017 gas price.

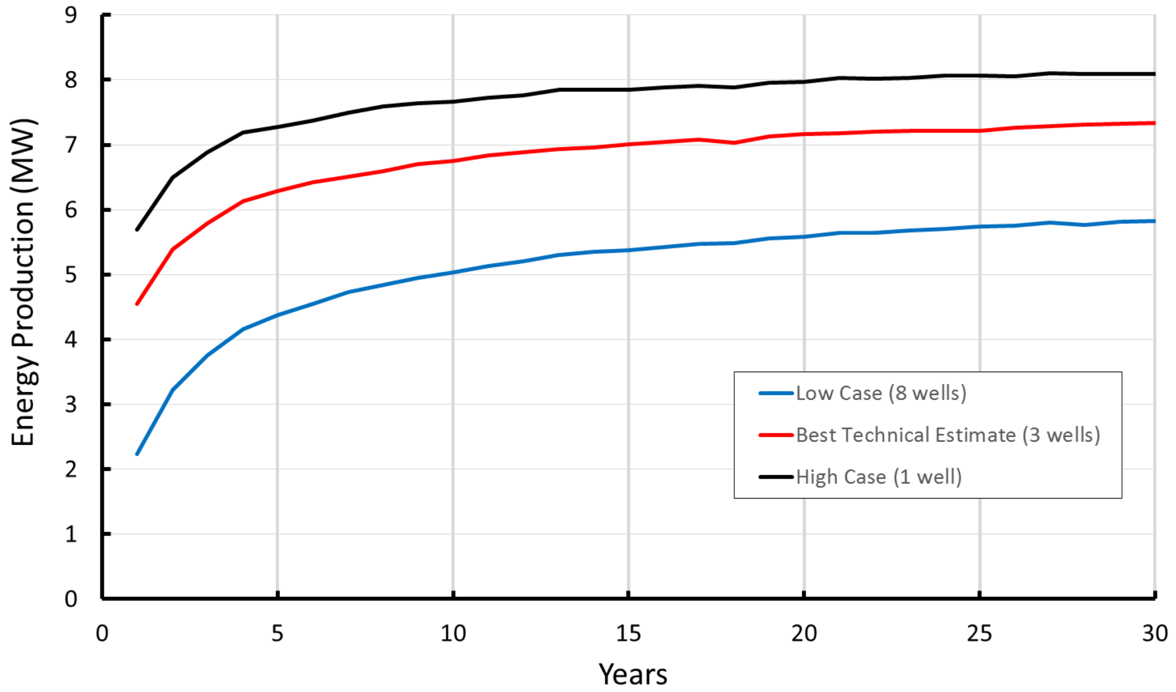


Figure 5. Simulated energy produced over time from well fields in the Low Case, Best-Technical Estimate and High Case models.

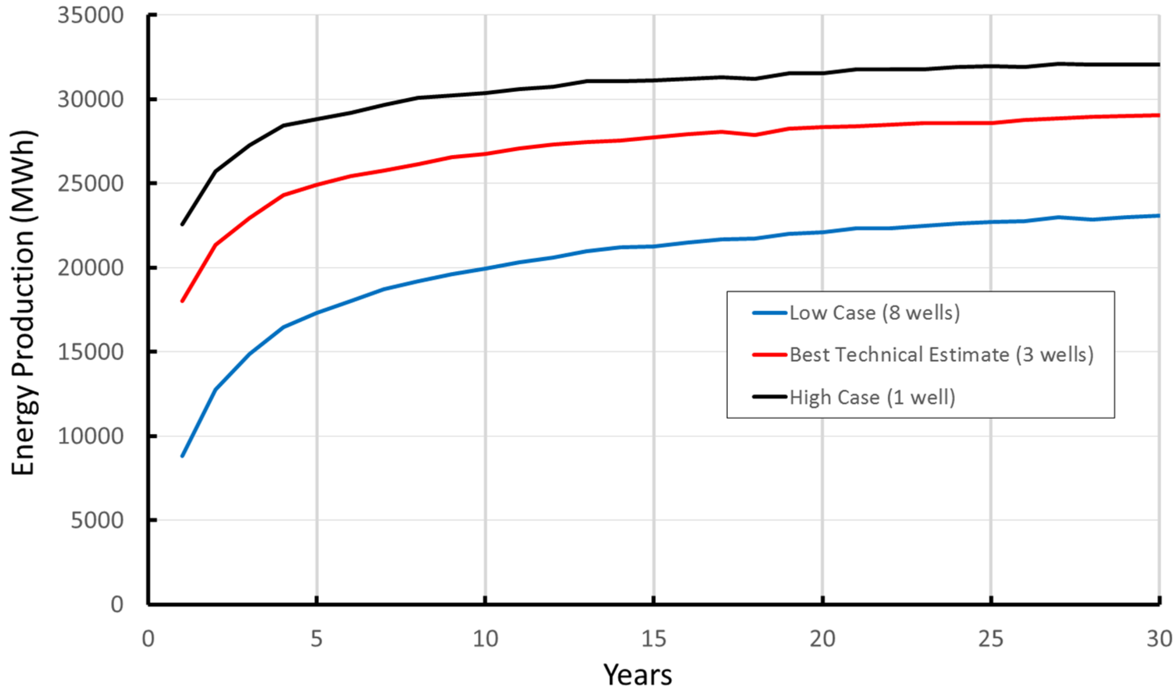


Figure 6. The simulated energy production in MWh over a 30-year time period for the Low Case, Best-Technical Estimate and High Case models.

### 1.3.3 Capital Expenditure

The capital expenditure (CAPEX) for the HTES project includes the money spent on the front-end engineering design (FEED), the wells (design, count, drilling and completion), the geothermal facilities (design and construction) and host modifications. The basis for the CAPEX estimates (Table 4) are presented in sections appendix 1 & 3. The large spread in the wells CAPEX from the Low Case through the High Case reflects the number of wells (production and injection) necessary to operate the well fields and facilities at flow rates of 150 $m^3$/hour.

Table 4. CAPEX in millions of Danish kroner (Dkk) for the Low Case, BTE and High Case models.

| CAPEX (millions Dkk) | Low Case | Best-Technical Estimate | High Case |
|---|---|---|---|
| FEED | 3 | 3 | 3 |
| Wells | 95 | 25 | 7 |
| Facilities | 18 | 18 | 18 |
| Facilities with heat pump | - | 32 | - |

| | | | |
|---|---|---|---|
| Host modifications | 2 | 2 | 2 |

### 1.3.4 Operating Expenses

The operating expenses (OPEX) for the facilities and pumps for the production and injection wells (Table 5) were calculated based upon estimates of the electricity demands (see appendix 1) and an electricity cost of 480 Dkk/MWh (an electricity price of 250 Dkk/MWh and an electricity tax of 230 Dkk/MWh). The OPEX also includes estimates of the cost of performing maintenance on and remedial treatment (workovers) of the production and injection wells (Table 6). It is assumed that minor well workovers will be required every fifth and some sort of major workover will be required every tenth year of operation.

Table 5. OPEX in millions of Danish kroner (Dkk) for the geothermal facilities.

| | Electricity Price (Dkk/MW) | Electricity Tax (Dkk/MW) | Electricity Cost (million Dkk) | Electricity Cost heat pump (million Dkk) | Field Operations (million Dkk) |
|---|---|---|---|---|---|
| OPEX | 250 | 230 | 2.5 | 2 | 2 |

Table 6. OPEX in millions of Danish kroner (Dkk) for workovers on the production and injection wells.

| | OPEX every 5th year | | | OPEX every 10th year | | |
|---|---|---|---|---|---|---|
| | Low Case | BTE | High Case | Low Case | BTE | High Case |
| Workovers (million Dkk) | 5 | 4 | 2 | 10 | 8 | 4 |

### 1.3.5 Finance Cost

The annual cost of financing the capital expenditures for the wells and geothermal facilities were calculated assuming a 6% loan over 30 years. The annual finance costs used in the business case models are presented in Table 7.

Table 7. Finance costs in millions of Danish kroner (Dkk) per year for the Low Case, Best-Technical Estimate and High Case models.

| | Low Case | BTE 80 | BTE 80 heat pump | BTE 90 | BTE 90 Heat pump | High Case |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| Financing – 6% over 30 years<br>(million Dkk/year) | 6.9 | 2.7 | 3.5 | 2.7 | 3.5 | 1.5 |

### 1.3.6 Cash Flow Models

Cash flow models were generated for the Low Case, BTE and High Case reservoir models using the production profiles presented in Figure 7, the CAPEX presented in Table 4, the OPEX for the facilities and wells presented in Table 5 and 6 and the finance costs presented in Table 7. The results of the cash flow models are presented in Figure 8, where it can be seen that the High Case and BTE 90 °C models (with and without a heat pump) all return a positive cash flow over a 30-year period; whereas, the Low Case and BTE 80 °C models have a negative or only slightly positive cash flow after 30-years of operations.

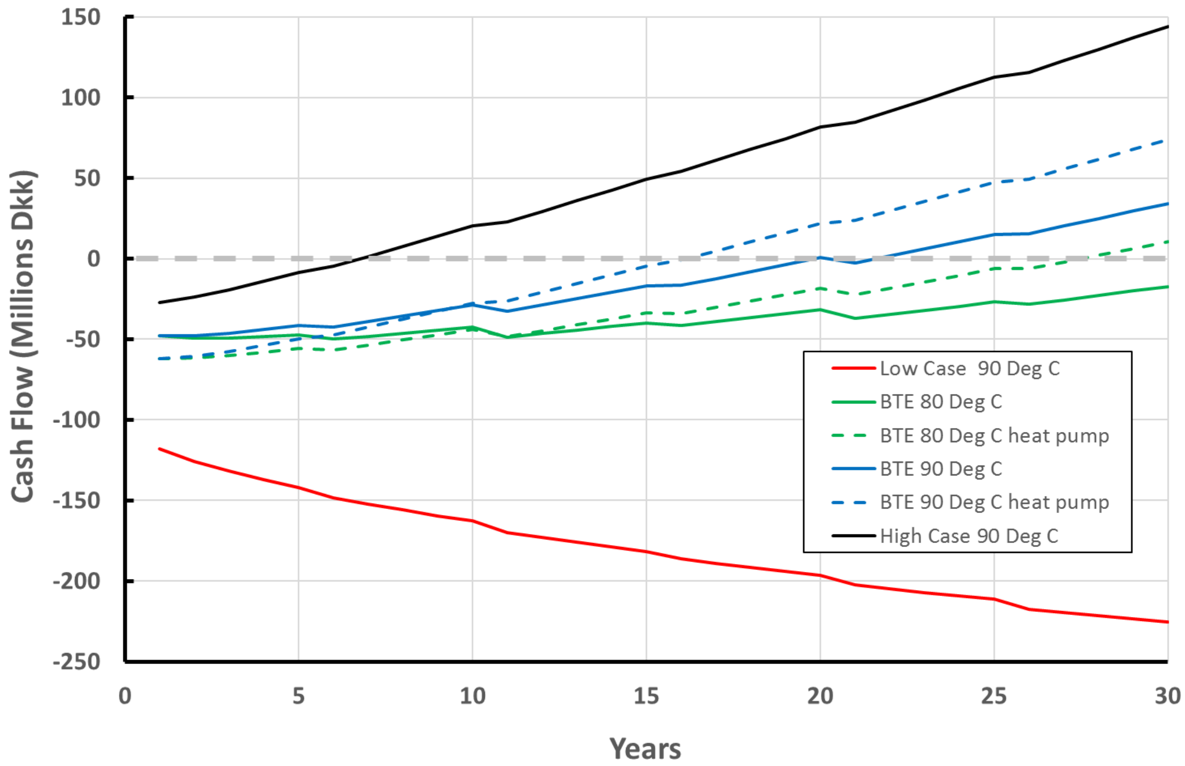


Figure 7. Results of the Low Case, BTE and High Case cash flow models.

## 1.4 Conclusions

- Numerical simulations of the injection of hot water in chalk reservoirs (storage) and the subsequent back-production of hot water (recovery) over 30-years show that the heat loss to the subsurface decreases with time from 14% during the first year of operations to about 20 and 15% by years 10 and 30, respectively.

- Cash flow models developed for Low Case, Best-Technical Estimate and High Case reservoir models show a positive business case for the Best-Technical Estimate and High Case models. These results establish a minimum reservoir permeability of 10 Md for a successful heat storage and recovery project in chalk reservoirs.
- The results of this project support the drilling and testing of a chalk heat storage and recovery well with the primary objective of proving-up the reservoir productivity (permeability).