Assessment of sedimentary geothermal aquifer parameters in Denmark with focus on transmissivity

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ABSTRACT

The latest assessment of the geothermal resources in Denmark concluded that the Danish subsurface contains huge geothermal resources. However, exploration and exploitation of geothermal energy involves large investments in wells and surface installations, and therefore, utilization of geothermal energy in Denmark today must – in order to succeed – both minimise the risk of not finding suitable subsurface reservoirs and insuring that well design, economics, development and operating of the geothermal plants are optimised.

During the recent years it has become clear that initial assessments of the subsurface geothermal potential are best determined from a number of geological parameters. These parameters are all dependent on geological processes and are presently being investigated and mapped by geological and geophysical methods, which are comparable to maturation of hydrocarbon prospects.

A method compiling and quantifying all available data and information is presented. The method addresses the variation in data quality in order to assess the most important geological parameters using all essential and available log and seismic analyses and integrating it with conventional core and production test analyses.

This evaluation forms the basis of analysing and comparing transmissivities calculated from different assessment methods, e.g. interpretation of log data combined with porosity-permeability relations against flow models and interpretation of well test data (production tests). A possible relation between log-derived transmissivity and a transmissivity derived from production test data will be discussed.

1. INTRODUCTION

Based on increasing activity during the last decade it is now expected that utilisation of geothermal energy will play an important role in the future energy strategy in Denmark. Denmark is a low-enthalpy area with minor regional temperature anomalies depending on the composition and thermal conductivity of the subsurface. The gradient increases with depth with a total of 25–30ºC/km, and - with present day technology - the potential reservoirs are not considered to be suitable for power production. Exploitation of the geothermal resources from low-enthalpy sedimentary basins is especially attractive in or near urban areas where it can be combined with already existing district heating systems. Based on regional play maps the exploration efforts will in the future be focussed toward areas with sufficient potential where local exploration models can be established by combining available geological and geophysical data. This paper focuses the geothermal heat produced from sedimentary basins and used for district heating.

The general guidelines used until now for suitable geothermal reservoirs in the subsurface fulfilling the requirements for safe, sustainable and economic exploitation of geothermal water are based on experience and knowhow from cooperation between the Geological Survey of Denmark and Greenland (GEUS) and Danish Geothermal District Heating (DFG). As a rule of thumb the reservoir needs to be reasonably thick (e.g. 10–50 m) and situated at a depth of 800–3000 m and preferably dominated by medium-grained or coarser-grained sandstones. The lower depth limit is selected due to the increasing risk of insufficient porosity and permeability at reservoir depths exceeding 3000 m. The upper limit is selected to ensure that formation water has a sufficient temperature. Usually, the temperature of reservoirs shallower than c. 800 meters in Denmark (i.e. 20–30ºC) is too cold for geothermal heat production.

The purpose of this paper is to present a method to assess geothermal aquifer parameters needed to estimate production efficiency, economic risks and concepts for a geothermal heat production prior to drilling of the first well. All subsurface exploration efforts involve geological risks related to the geological complexity of the subsurface and the amount and quality of the available data (Table 1). It is therefore important that the methods check, compile and quantify available data and information using quantitative conditioned geological models of the subsurface geology, and addresses the variation in data quality in order to assess the most important geological parameters such as grain size and shape, sorting, cementation, burial depth, thickness, net/gross (or net-to-gross) ratio, continuity (presence of faults or lateral lithological changes), porosity and permeability of the reservoir sandstone units, and temperature of the formation water. Water chemistry is another important parameter in evaluating the suitability of the reservoirs for long-term production to avoid precipitations clogging up the wells and surface installations.

The overall workflow involves three different models each describing various relations between important parameters (see also Magtengaard and Mahler, 2010). All three models focus on assessment of the reservoir quality and production efficiency and are connected through the transmissivity. It is essential that the transmissivity (and permeability) values are calibrated with the available data and comparable between the three models:

1. The **geological model** (including structural, stratigraphic and sedimentological models) is used to assess geological related reservoir data to estimate transmissivities and temperatures and other important parameters for a given geothermal aquifer.
2. The **flow model** is a computer model (reservoir simulation model) that in three dimensions calculates the water flow and changes in pressure and temperature as function of time and space. Based on production data i.e. production rate and life-time the optimal well design for a geothermal plant can be assessed.
3. **The plant simulation model** is a computer model that calculates heat production costs based on the local transmissivity, temperature and heat demand parameters.

Only model 1 and 2 will be described in this paper, as the compilation of data and the integrated use of a geological model and a flow model forms the basis for the subsequent evaluation. The main focus will be on the assessment of transmissivity and production efficiency. Transmissivity here is defined as the ability of an aquifer (reservoir) to allow the flow of fluid through a certain area, e.g. on the way to the well. The transmissivity is the product of the permeability (a property of the rock only, related to the interconnectedness and size of fractures or pores) and the thickness of the sandstone aquifer through which the fluid is flowing, here defined as the (effective) net sand thickness of the best potential sandstone units.

2. METHODOLOGY

All essential and available data such as well log data, seismic data, conventional core analysis data including porosity and permeability, well test data and water analyses are incorporated. Calculation of transmissivity includes e.g. interpretation of log data combined with porosity-permeability relations, reservoir simulation models and interpretation and calibration with well test data (production tests).

The work presented is part of a project that brings together quality-checked geological data and information relevant to assessment of the geothermal potential. A Web-based GIS platform will be constructed, so that users in a clear and easy way can get an overview of the density and the quality of the geological data, the complexity of the subsurface and the related assessments. Thematic maps will be constructed by quality checking data, analyse methods and processes, interpretation and compilation of geophysical, geological, petrophysical and rock mechanical data contained in different databases, and will follow the workflow described in the evaluation process.

2.1 Evaluation Process

Geothermal aquifers can be evaluated from well data in terms of A) reservoir quality and B) reservoir production efficiency. Reservoir quality depends on estimates derived from petrophysical analysis of existing well logs. The reservoir production efficiency is the product of reservoir quality (i.e. sand/shale ratio, net/gross ratio and accumulated net sand thickness, porosity and permeability), continuity (stratigraphical complexity and faults) and production properties (permeability/transmissivity, temperature and salinity).

The evaluation process must always be based on all relevant and available data. The potential reservoirs and their quality are identified from stratigraphic, sedimentological and petrophysical analyses of well data comprising well logs, cuttings samples and cores (incl. sidewall cores). Uncertainty and risks related to amount and quality of these data together with seismic data must furthermore be assessed (Table 1).

The evaluation process that assesses the most important parameters consists of a step-wise evaluation, where some of the most important steps are described in the following:

1. Macro reservoir parameters:

A. By correlating the stratigraphy to the seismic data using well ties the **burial depths and thickness variations** of the reservoir-bearing formations can be mapped. Lithological changes caused by pinch-out, erosion or depositional features such as clinoforms, channels, thin discontinuous bedding, or other facies changes related to the depositional environments of the reservoirs are analysed by close correlation of well logs sections, studies of cores and cuttings samples and are described by a sedimentological model. Subsequently, the seismic data is analysed for faults that cut the reservoirs in order to avoid the drilling of exploration wells close to faults that may form hydraulic barriers.

B. **Gross-thickness** based on well data and seismic data is the total aquifer thickness of interbedded productive sandstones and non-productive sandstones and shales/claystones.
C. **Net Sand thickness** is the accumulative thickness of producing sandstone layers estimated in wells and defined from a geological derived net/gross ratio defining the fraction of the gross-thickness of sandstone layers that has producing properties.
D. **Net/gross ratio** of reservoir units (reservoir sandstones versus non-reservoir rocks) is estimated by quantitative analyses of well logs with the application of cut off values on shale content and requirements on minimum porosity of the reservoir sandstones. The combination of a depositional model and net/gross estimates with a minimum porosity cut off provides a useful estimate of the reservoir potential.
E. The **continuity factor** of the Net Sand thickness is a result of stratigraphic and structural continuity and describes the hydraulic connection between the production and injection wells – assuming a doublet well design with 1–2 km between the well heads. The Continuous Net Sand thickness value is subsequently used for the technical and economical calculations when the price of the heat is estimated, and the continuity factor depends on the geological model, the thickness and vertical facies distribution of the individual sandstone layers and nearby identified fault zones.

2. Internal reservoir quality parameters:

F. The well logs are interpreted and the **'most likely' porosity log (PHIE**) is calculated. An uncertainty interval is subsequent added by respectively subtracting 2 porosity units and adding 2 porosity units to the 'most likely' porosity values**;** this uncertainty interval is later used in the flow model.
G. Based on the calculated 'most likely' PHIE the **'most likely' permeability log (PERM_log)** is estimated by a porosity-permeability relation derived from core analysis. An uncertainty interval is subsequent added by respectively multiplying the permeability by 5 and dividing the permeability by 5. Thus, the permeability log is estimated from a relation between porosity and permeability measured on a large number of core plugs including core analysis data from areas outside the particular area in question. Ideally, formation specific cores are used. The permeability is calculated as a weighted average – based on the assumption that the formation consists of parallel layered beds of different transmissivities**.**

3. Reservoir production properties:

H. The **flow weighted** cumulated **transmissivity** is estimated based on the estimated permeability log and net sand thickness.
I. The **temperature** of the reservoir aquifer will in the initial stage be estimated from the application of general depth-temperature relations, but will at a later stage be estimated from more well-defined 3D temperature models.
J. The **brine chemistry** is found from analyses of formation water and has implications for density, heat conductivity, heat capacity, bubble point, corrosion of installations, scaling and cementation, and will in the initial stage be estimated from the application of general depth-salinity relations

Geothermal aquifers must furthermore be spatial constrained. This is done by interpretation of seismic data to both determine the communication within the reservoir volume, but also to describe the structural development (faults, fractures and folds).

The parameters used in the evaluation process are further addressed based on data, experience and a set of general rules defined by preliminary criteria and relations between the related parameters (Table 2). The objective is to give an overview of the most important parameters along with the empiric criteria used when assessing the potential reservoir quality and production efficiency of a particular reservoir section. Notice that the preliminary defined criteria and geological considerations in Table 2 is at a preliminary stage, and will subsequent be adjusted as our experience increases, and it should be noted that in the current version the evaluation workflow does not provide any economic assessment of the reserves.

Table 1: Data quality and coverage

Data quality and coverage	Good Data	Limited Data	Poor Data
Criteria	Wells < 10 km w. full log suite; Good 2D (and 3D) seismic data	Wells within 10–30 km w. reduced log suite; Medium–Good 2D seismic data	No wells within 30 km; Older logs and seismic data of poor quality

Other risks must also be evaluated, e.g. in the Danish subsurface thick clay sections from the Fjerritslev Formation represents drilling risks, and it is therefore important to estimate the thickness and composition of the formation and understand when clay-rich sections represents a drilling risk.

2.2 Estimation of V_{shale}, effective porosity (PHIE), permeability and transmissivity

The **shale volume** (V_{shale}) is calculated from the gamma-ray (GR) log using empiric well-specific shale parameters (i.e. background radiation (GR_{clean}) due to radioactive heavy minerals or mica other than clay/shale and the GR response for pure clay (GR_{clay})). If a gamma-ray log is not available V_{shale} is estimated from the SP log. The calculated **porosity log** (PHIE) is determined from a shale-corrected density log using the calculated V_{shale}. If the density log is not available the porosity is estimated from the sonic (DT) log.

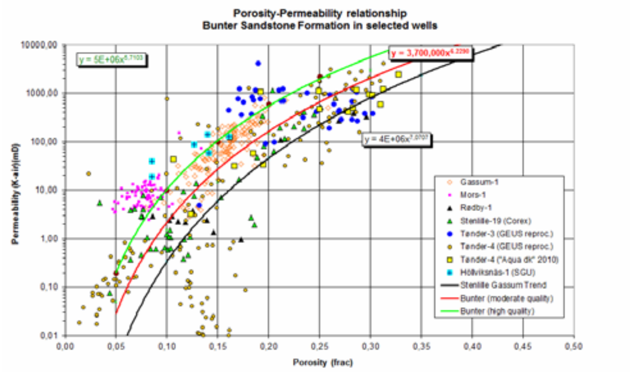

Figure 1: Relation between porosity and permeability for sandstones based on selected conventional core analysis data from the Bunter Sandstone Formation. The most likely relation (red line) has been used in the Copenhagen area for assessment of the Margretheholm wells. The uncertainty on the estimated permeability is, however, quite large, so the permeability distribution is preferably presented as an average trend line together with a range, i.e. an uncertainty band. The average trend line describes the most likely porosity-permeability relation.

Technically, it is not possible to log the permeability in a well directly; however, a **permeability estimate** can be derived from a porosity-permeability relationship. The porosity-permeability relation is established using a regional dataset, which encompasses data from several Danish onshore wells including core analysis data and sidewall cores (Fig. 1). This non-linear relationship has been used for assessing the **average gas permeability**, realizing that a deviation from this trend line obviously exists on a local scale. The log-derived gas permeability is calculated from the log porosity by using $PERM\_log[mD] = a*(PHIE)^b$, where a and b are constants. Consequently the log-derived gas permeability is not a direct measurement, but a calculated estimate. It is therefore suggested – until better data is available – to associate uncertainty ranges to the average gas permeability estimate, where the high case value is 5 times the average value and a low case value is the average value divided by 5. The use of this (wide) uncertainty range insures that more than 90 % of the core data in Fig. 1 will be incorporated in the estimation of the gas permeability, and that this – together with an uncertainty range - can be used as reasonable input for the flow model.

A 30% V_{shale} cut-off is applied to exclude claystones and shaly sandstones with a poor reservoir potential. Furthermore, a porosity cut-off of 15% is also applied to qualify and characterise the potential reservoir sandstones (Table 2). The net/gross ratio is calculated for each formation separately, and equals 'net sand thickness' divided by 'total formation thickness'.

The **gas transmissivity** for each formation/stratigraphical unit is calculated from the log-based permeability estimates. During logging, petrophysical measurements are normally performed for every ½ ft., and each of these intervals is evaluated as a reservoir or non-reservoir interval by applying shale and porosity cut-offs. For each reservoir interval a permeability and corresponding transmissivity is estimated. Adding up all ½ ft. reservoir intervals provides the accumulated net sand thickness, while adding up the transmissivity values provides the average formation transmissivity. The **average gas permeability** for each reservoir is calculated by dividing the transmissivity by the net sand thickness (a similar approach to estimate average permeability, i.e. the weighted-average method, is described in Ahmed, 2001).

Table 2: Evaluation of key parameters; preliminary criteria and geological considerations.

	Positive Indications	Reasonable Indications	Cautionary Indications
1. Macro reservoir parameters			
Depositional setting (grain size and shape, sorting heterogeneity and cement type)	Shoreface, fluvial and aeolian sand	Deltaic sand	Tidal sand
Lithology (Grain size/sorting)	Coarsed to medium-grained; well sorted	Medium-grained; moderately sorted	Fine to very fine-grained; poorly sorted
Depth To [m]	800–2500	2500–3000	< 800; > 3000
Gross Thickness [m]	> 100	50–100	< 50
Net Sand Thickness [m]	> 50	15–50	< 15
Sedimentological continuity	Large continuity; Homogeneous	Moderately continuity	Low continuity; Heterogeneous
Structural continuity	No deformation; Fault dist. > 2 km	Deformed; Fault dist. 1–2 km	Very deformed; Fault dist. < 1 km
2. Internal reservoir quality parameters			
Avg. Porosity [%]	> 25	15–25	< 15
Avg. Gas Permeability [mD]	> 500	50–500	< 50
3. Reservoir production properties			
Flow weighted Gas Transmissivity [Dm]	> 15	8–15	< 8
Temperature [°C]	> 28	22–28	< 22
Diagenesis/Cementation	Weak/loose;Little/no cementation	Moderate cementation	Extensive Cementation
Salinity	‘	‘	Near saturation
Other risks			
Properties of Shale-rich sections	Silty-sand, silt/sand layers < 100 m	Medium clay content 100–450 m	High clay content > 450 m

2.3 From the geological model to the flow model

A 3D geological model is constructed from well data and seismic interpretation of the reservoir formations, using all possible information compiled during the evaluation process (see also Table 2). The geological model is then exported to the flow model, which can calculate changes in flow, pressure and temperature as function of space and time. Eclipse 100 - a standard reservoir simulation software - is used for flow simulations including the in-build temperature option.

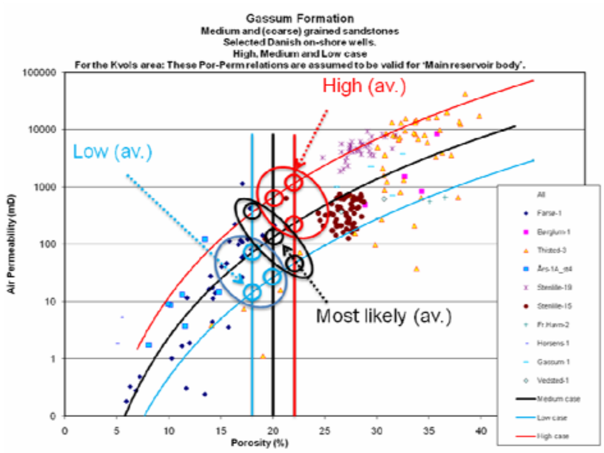

Figure 2: The figure shows the principal concept of 9 different simulation scenarios ordered in to three groups; a "Low", "High" and "Most likely". Simulation results are reported as an average number for each group. The medium, low and high case values on the porosity axis varies in the model according to the porosity log, the uncertainty band (low and high) is kept constant with ±2% porosity uncertainty range.

Uncertainty in key reservoir properties, i.e. porosity and permeability, is addressed by adding uncertainty bands on these parameters, and total of 9 different scenarios of the potential are normally simulated (Fig. 2). Thus, the assessment of the geothermal potential is presented as a spread in reservoir productivity illustrated as low, most likely and high values for simulated production and injection.

Due to the sparse data coverage for many of the potential geothermal sites a simple layer-cake modelling approach is adopted, where major faults are incorporated as being either fully closed or open to flow. The vertical variation in properties is constructed from well log information, and the laterally variation in reservoir properties can further be optimised by the incorporation of production data. Seismic attribute analysis may also bring information on the lateral property variation, but is only possible where 3D seismic data are acquired.

Based on well configurations and production, different scenarios can be simulated and the productivity of the geothermal reservoir can be optimized.

2.4 The impact from diagenesis

The production efficiency can be assessed based on the evaluation process, and the simulated results from the flow model. Furthermore, it can be influenced by the geological history of the reservoir resulting in different degrees of diagenesis. In the Dnaish subsurface, diagenetic cementation generally increases with depth preventing the use of reservoir units deeper than 3000 m, and causing major risk in the depth interval between 2500–3000 m (Table 2). This limits the maximum temperatures of potential geothermal reservoirs to 80–90°C.

Significant work are at present carried out to improve the understanding of how porosity and permeability, are influenced by parameters such as grain size and shape, sorting, facies, burial depth, diagenesis and clay and cement content. Conventional core analysis and multivariate analysis of the combined petrographic-porosity-permeability dataset has been used to evaluate the influence from a number of parameters, such as burial depth, facies, detrital mineralogy and diagenetic changes. Of these parameters, grain size, burial depth and burial related diagenesis are particularly important in defining the porosity-permeability trend (Weibel, 2012). Improved porosity-permeability trends are obtained by subdividing the samples into formation specific grain-size groups. Furthermore, if sorting is very poor, as observed in clayey or heterolithic sandstones, it reduces both porosity and permeability considerably.

The initial porosities and permeabilities are defined by the grain size and sorting at the time of deposition which again is controlled by the energy of the depositional environment. Mechanical compaction and diagenesis during burial gradually reduce the original porosity and permeability of the sandstones. In the Danish surface, the diagenesis is primarily a consequence of increased amounts of quartz cement. Especially, quartz cementation and pressure solution reduce the average pore and pore throat sizes and consequently reduce the permeability more than porosity. The diagenetic changes that reduce porosity, are accompanied by a reduction in permeability, and as diagenesis becomes increasingly more effective, the permeability is reduced more than the porosity.

In the coarse-grained sandstones, illitised mica reduces the permeability without affecting the porosity. In fine-grained sandstones, permeability-reduction is due to micro-anisotropy associated with deformed mica laminae with incipient pressure solution or siderite cement along mica laminae. The micro-anisotropic diagenetically formed barriers affect permeability more than porosity. As our understanding of the diagenetic impact increases, the relevance of using the porosity-permeability trend will be better constrained, leading to improved permeability assessments and geological prognoses of reservoir properties in undrilled sections.

3. CASE STUDY FROM THE DANISH AREA

The development of the underground of Denmark is dominated by some major structural elements that significantly have influenced the deposition of reservoirs. Through geological time 5 regional distributed sandstone reservoirs, all with large geothermal potential have been deposited sourced mainly from the Skagerrak-Kattegat Platform and Ringkøbing-Fyn High (Fig. 3; see also Mathiesen et al., 2010; Michelsen et al., 2003; Nielsen, 2003). The depths of the reservoirs vary considerably from area to area, and the most prospective reservoir is the well-described Gassum Formation. The Bunter Sandstone Formation is another potential reservoir but is less known; locally, the Frederikshavn Formation, the Haldager Formation and the Skagerrak Formation also contain good reservoir units. Due to erosion reservoirs are nearly absent over the Ringkøbing-Fyn High (Fig. 3).

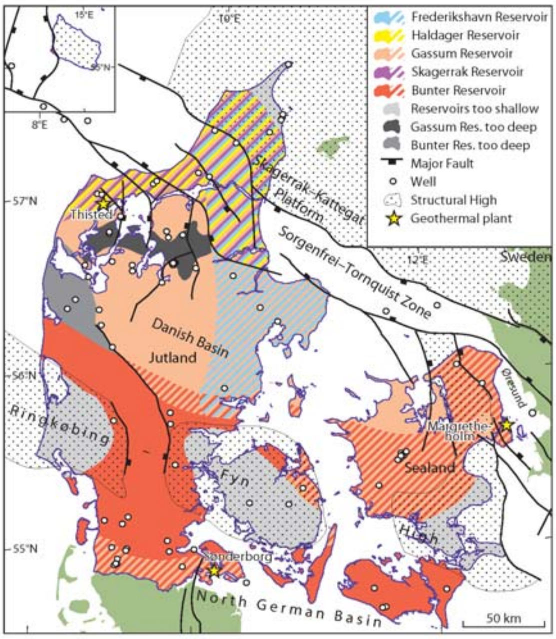

Figure 3: Map showing the distribution of the potential geothermal reservoirs in Denmark where they are expected to occur with a thickness of more than 25 m in the 800–3000 m depth-interval. The dark-grey and black areas indicates where the reservoirs are buried too deep; the light-grey areas indicate where no reservoirs are expected to be present (Ringkøbing-Fyn High) or are too shallow buried (< 800 m; northernmost Jutland). The hatched areas indicate two or more reservoirs with a geothermal potential. The existing deep wells, location of the Thisted, Margretheholm and Sønderborg plants are shown.

The evaluation of reservoir quality of a given reservoir interval is based primarily on wireline logs from the nearest wells, core analysis data if they exist, along with relevant information extracted from well completion reports and on the regional geology. In this context the general knowledge of the regional geology combined with information on the depositional setting is utilised.

As described in the evaluation process the petrophysical analysis results in sub-division of the lithostratigraphic units into reservoir units (i.e. sandstone) and non-reservoir units (i.e. shale). Furthermore, the lithologies of the drilled well sections are interpreted using core samples, description of cuttings and information from well completion reports and mud logs.

3.1 The Gassum and Bunter Sandstone formations at the Copenhagen test site

The sandstones of the Danish Upper Triassic–Lower Jurassic Gassum Formation and Lower Triassic Bunter Sandstone Formation have been examined in order to further address the relations between porosity and permeability locally and on a regional scale (Fig. 1 and Table 3). The petrophysical evaluation of the Gassum Formation sandstones in the example indicates relatively high average porosities, with average porosities exceeding 20%. The log porosity and gas permeability estimates corresponds well with the core analysis data performed from the nearest well.

Compared to the Gassum Formation, the deeper situated Bunter Sandstone Formation shows lower average porosities. However, the Bunter Sandstone Formation has only been encountered in few wells. Prior to producing water from the reservoir at test site, a communication test was conducted between the production and injection wells in the Bunter Sandstone reservoir. A well communication fluid transmissivity of 12 Dm valid for the main Bunter reservoir interval was interpreted from the well test data by DONG E&P (2004), leading to a fluid permeability of 417 mD on the assumption the net sand thickness is 28 m (‘Pay zone’ in Table 3). Similarly, GEUS has on the basis of core and log data from one of the Copenhagen wells calculated a gas transmissivity of 16 Dm (signifying a fluid transmissivity of ~8 Dm) for the main reservoir interval, leading to a gas permeability of 500 mD that corresponds to a fluid permeability of *c*. 250 mD. The difference in interpreted fluid permeability is presumably related to factors such as different scales (reservoir and laboratory conditions), up-scaling problems, micro-fracturing within the sandstone reservoir rock, presence of thin high-permeable stringers that cannot be resolved by conventional wireline logs etc. Furthermore, it should be kept in mind that the log-derived permeabilities have not been calibrated to local core permeability data, as no cores were cut in the reservoir section at the test site location. Locally, the presumed porosity-permeability relationship may deviate from the regional porosity-permeability trend.

Table 3: Important key parameters from three operating geothermal plants in Denmark.

Geothermal plant	Established [year]	Well design (d=doublet)	Well head distance [m]	Reservoir [Fm]	Depth To [m]	Temperature [°C]	Salinity [wt.%]
Thisted	1984	d	1507	Gassum	1250	45	15
Copenhagen*	2005	d	1240	Bunter Sandstone	2600	74	19
Sønderborg	2013	d	760	Gassum	1200	48	15

Geothermal plant	Log interpretation				Well test	
	Gross formation [Fm tck; m]	Net reservoir sand [m]	Avg. Porosity [%]	Gas transmissivity [Dm]	Fluid transmissivity [Dm]	Pay zone [m]
Thisted	135	83	27	185	100–110	30
Copenhagen*	299	60	20	16	12	28
Sønderborg	61	39	39	240	129	35

*The Copenhagen porosity-permeability relationship is based on Bunter Sandstone Formation data originating from wells outside the Copenhagen area, as no core analysis data are available from the Margretheholm wells. At a later stage, when more data are available it may turn out that a Margretheholm porosity-permeability relationship will deviate from the regional porosity-permeability tend.

4. DISCUSSION

At present, challenges in many Danish areas arise from the limited data and absence of good quality data. In several Danish wells a full log suite is not available and a full-scale modern petrophysical evaluation is, therefore, not possible, and in others, the lowermost part of the potential reservoir formation is not logged due e.g. to technical problems during logging, leading to uncertainty in determining reservoir parameters.

Sparse data sets make the spatial understanding uncertain and the assessment of the sensitive parameters difficult. Quantitative spatial assessment must therefore be based on the petrophysical analysis integrated with seismic mapping, geological models (i.e. understanding and experience) and flow models (i.e. well design, production rate, lifetime estimates).

Due to the limited database the evaluation process has to rely on geological descriptions and models of the subsurface geology. An essential part of this is a relation between the geological model and the expected production transmissivity defined by the spatial distribution and characteristics of the potential geothermal aquifers regarding distribution, composition and physical properties.

Furthermore, it is important to realize that the regional porosity-permeability relationship described in Figure 1 is based on gas permeability and not liquid permeability as only a limited amount of permeability data is available for the latter. At present, it is assumed that the gas permeability is approx. twice the size of the liquid permeability, but this anticipation is questionable, and more data is needed before we can determine whether this relation is a reasonable assumption.

Average formation permeabilities based on core measurements and permeabilities derived from interpretation of well test data are not necessarily comparable as pointed out by Ahmed et al. (1991). They stress that, by establishing a correlation between unstressed core plug permeability and drillstem-testing (DST) permeability and then using the correlation with other unstressed core plug permeabilities to evaluate the flow potential of other zones, may be useless unless the scale factor, measurement environment, and physics are adequately considered. The scale factor considers the relative size of the volumes being investigated and the nature of heterogeneity, and the measurement environment and physics consider the state of the rock environment, fluid saturation distribution, flow direction, and sensitivity of the measured or inferred variables that constitute permeability calculations.

It is therefore important to find a 'test site' where a well-described potential reservoir formation is present, and where both core analysis and production tests exist (e.g. DST tests). First of all, a simple concept reservoir model to simulate the pressure development and production rates is needed together with estimated permeability log are used, based on core analyses and the resulting porosity-permeability relation. In the simulation model the permeability log is subsequently adjusted until a good match between measured and simulated pressure development is obtained ('history match'). This simple workflow could help us to better associate scale factors and uncertainties to the geological complexity of the Danish subsurface. Similar to the oil and gas context, determining the scale of the heterogeneities that impact - and to what degree - the reservoir quality and flow efficiency is also crucial when assessing the production efficiency.

5. CONCLUSIONS

The presented workflow compiles and outlines a preliminary evaluation process and methods to quantify values and variation for the most important geological parameters needed to assess the transmissivity and the production efficiency for a low-enthalpy reservoir in sedimentary basins. The workflow is relevant for evaluating the geothermal potential for district heating, as it addresses essential parameters such as porosity, permeability, diagenesis, transmissivity, reservoir depth, net sand thickness, temperature gradient, salinity, pressure drop and flow rates.

Further work should focus on factors that influence transmissivity (i.e. permeability). We need a better understanding of the relationship between porosity and permeability and to what degree factors such as grains size and shape, sorting and clay content influence the initial mechanical compaction, and cementation, and recognizing that diagenesis is a function of climate, depositional environment (mineral composition), sediment source area, transport distance and burial depth. Integration of diagenesis and temperature history obtained from basin modeling may further increase the understanding of diagenetic impact on development of the reservoir through time.

Other topics need additional work, one being how to assess the diagenetic effects on the permeability and the porosity versus depth relationship in areas away from well control, on effects of different brine compositions and to obtain an better definition of a consistent relation between gas and fluid permeability.

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