Count Down Net Ø Carbon

Use of heat from wells

SPARK-2137

Net Zero Technology Centre
Technology Driving Transition

EnQuest

Petrofac

CeraPhi energy

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

GLOSSARY OF ABBREVIATIONS

- BHP: Bottom Hole Pressure
- BHT: Bottom Hole Temperature
- BOPD: Barrels of Oil Per Day
- BPD: Barrels per day
- BWPD: Barrels of Water Per Day
- CCS: Carbon Capture and Storage
- CeraPhiWell™: CeraPhi Closed-loop Advanced Geothermal System Patented Technology
- CoP: Cessation of Production
- Cp = Specific Heat Capacity of Fluid (J/kg°C)
- ΔT = Well Outlet Temperature – Well Inlet Temperature
- EOR: Enhanced Oil Recovery
- EOWR: End of Well Report
- Fm/Fms: Formation / Formations
- GWP: Global Warming Potential
- HIP: Heat in Place (Petajules – PJ)
- HP: High Pressure
- HPHT: High-Pressure & High-Temperature
- HUD: Hold up depths
- HVAC: Heating, Ventilation, and Air Conditioning
- kWe: Kilowatt Electric
- kWth: Kilowatt Thermal
- ORC: Organic Rankine Cycle
- Lmst: Limestone
- LKCF: Lower Kimmeridge Clay Formation
- LP: Low Pressure
- l/s: Litres per second
- LWD: Logging While Drilling
- MD: Measured Depth
- MDBRT: Measured Depth Below Rotary Table
- mD: Millidarcy
- MMbbls: Million Barrels
- MMboe: Million Barrels of Oil Equivalent

- MSM: Magnus Sandstone Member
- Mst: Mudstone
- MWe: Megawatts Electric
- MWh: Megawatt Hour
- MWth: Megawatts Thermal
- N:G: Net to Gross
- NW: North West
- NZTC: The Net Zero Technology Centre
- OPEX: Operational Expenditure
- ORC: Organic Rankine Cycle
- P&A: Plugging and Abandonment
- PLT: Production Logging Tool
- POOH: Pull Out of the Hole
- $\emptyset$: Porosity (parts per unit)
- P: Potential Power output (MWe)
- PFD: Process Flow Diagram
- PSI: Pounds per Square Inch
- PW: Produced Water
- P10, P50, P90: Percentiles 10, 50 and 90
- Rf : Recovery Factor
- RIH: Run In Hole
- Sst: Sandstone
- TBC: To be confirmed
- Ti: Reinjection temperature (^{o}C)
- TOC: Top of Cement
- TOL: Top of Liner
- Tr: The cell or voxel temperature (reservoir temperature) (^{o}C)
- TVD: True Vertical Depth
- TVDSS: True Vertical Depth Subsea
- UKCS: United Kingdom Continental Shelf
- VIT: Vacuum Insulated Tubing
- WL: Wireline Logging
- WP: Work Package
- 2C Resources: Unrisked best estimate scenario of Contingent Resources

1 Executive Summary

The Net Zero Technology Centre (NZTC) commissioned a study with CeraPhi Energy, EnQuest and Petrofac to assess the potential on the Magnus offshore platform of converting heat energy from repurposed wells using the novel CeraPhiWell™ technology and the produced water stream into clean electrical power using Organic Rankine Cycle (ORC) generators. This would show the potential to decarbonise both Magnus and also other oil & gas operations in the United Kingdom Continental Shelf (UKCS).

EnQuest made available a large amount of data and drawings to allow a detailed assessment of the platform wells and topsides by CeraPhi and Petrofac, this assessment was structured into seven main Work Packages.

The first five Work Packages looked at the two main sources of heat energy available: the produced water and the wells. The sixth Work Package reviewed the ORC technology and the potential electrical power outputs that could be achieved. The final Work Package drew on these assessments to consider the options for Magnus during the current and future operational stages, and also what opportunities could be considered for the UKCS.

The produced water stream on Magnus is currently 165,000 Barrels Per Day (BPD) at 100 ^{o}C. The platforms other heat users such as glycol reboiler and fuel gas heater were examined to determine if this heat source could be directly used for those processes, however it was found to be unfeasible in all cases.

There are 28 well slots on Magnus but only 25 are currently in production and only these were considered for repurposing during the study. The extensive well data was reviewed to assess the key aspects of the wells, including the history, integrity and operational status. All 25 wells were assessed as having sufficient integrity for repurposing, and the operational True Vertical Depths (TVD) were similar ranging between 2,943 m and 3,452 m meaning the expected bottom hole temperatures would also be similar. The production liners were either 5 ½" or 7" which would affect the hydraulic characteristic of a repurposed well.

A full summary table of information and a preliminary well schematic showing the installation of a CeraPhiWell™ to repurpose it for geothermal heat production was prepared for each of the 25 wells.

The Magnus reservoir geology and structure was reviewed and the geothermal gradients for each well was assessed, with the lowest being at 34 ^{o}C/km, the highest at 48 ^{o}C/km with the overall gradient approximately at 40 ^{o}C/km.

The thermodynamic and hydraulic modelling was then undertaken to determine the optimum flowrate through a repurposed well in order to extract the highest amount of sustainable heat energy. A number of modelling runs were prepared using different flowrates, temperature differentials, tubular materials and amount of insulation. It was found the optimum flowrate for all the wells was 5 litres/second using Vacuum Insulated Tubing (VIT). This gave an approximate thermal energy output of 440 kWth per well resulting in an overall output for 25 repurposed wells of 11 MWt_h.

In additional to considering repurposing existing wells with the CeraPhiWell™ technology, the potential for both, a cross-reservoir open-loop traditional geothermal system and also drilling a new specifically designed CeraPhiWell™ was evaluated.

The Magnus reservoirs connectivity was found to be complex. However, the extensive lateral connectivity of the Magnus Sandstone Member Formation and the availability of good data suggested this be the target candidate for cross-reservoir connectivity evaluation. A high-level volumetric method for evaluating geothermal resources was used, resulting in Heat in Place and the Power Potential output of a hypothetical power plant that could be supported by this resource, and found to be between 3 MWe (low case) and 12 MWe (upper case). This First Order Method has to be regarded as a simplified approach, taking into account the uncertainties related to the assumptions on reservoir parameters, i.e., Recovery Factor (Rf).

The thermal output from the current wells operating in an open loop system was looked at, recognising this is complex to model accurately. Thermal output from each field sector was estimated and the overall output for the whole field was 15.76 MWt_h.

A new drill CeraPhiWell™ was investigated but recognising there are no available slots on Magnus this was to allow comparison of output with a repurposed well. A sidetrack from an existing well was considered but further work would be required to understand the potential. As a new well is designed to maximise the fluid flow rate and hence the heat output, the flowrate could be increased to 20 litres/second and the thermal energy delivered could be 1.6 MW per well.

Having estimated the thermal output available from the different heat sources (produced water, closed loop CeraPhiWell™ and open loop cross-reservoir) a review of Organic Rankine Cycle (ORC) technology was undertaken. The ORC system is widely used for generating electrical power from input temperatures from as low as 80 ^{o}C and it uses an organic working fluid with a lower boiling point than water. Two alternative layouts were looked at, one where the ORC components would be installed on the platform as individual items and connected in-situ, and the other where a pre-assembled modular containerised system would be used.

For each heat source, a preliminary process flow diagram was prepared and an equipment list for a bespoke system was produced. The process flow preliminary design was slightly different for each heat source option. Parasitic loads for the process, including circulation pumps within the ORC unit or for the well fluids, were assessed to calculate the net power generated and overall efficiency of the system when considering the gross thermal input energy. For each case this was around 10-11 % which is the normal range for ORC systems operating at the fluid temperatures available on Magnus.

The three heat source options were considered in respect of the operational phases for the Magnus platform; the current production phase, decommissioning and post-decommissioning. During current operations only the produced water stream would provide a realistic heat source, as there are no suspended wells available for repurposing and a cross-reservoir system could not be used. Either a maximum of 2.2 MWe or 4.5 MWe could be generated, depending on the ORC configuration deployed. During decommissioning the practicalities of installing new equipment while also removing redundant equipment would be very challenging, however if wells could be repurposed after being suspended then the potential power generation could be either 1.0 MWe or 2.1 MWe depending on the ORC configuration.

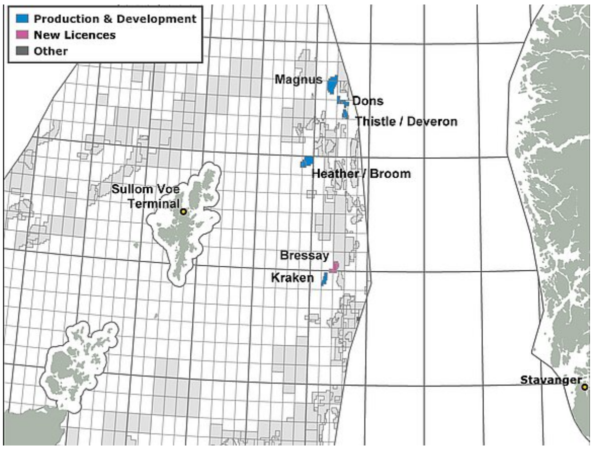
The post-decommissioning phase appeared to offer the most significant potential for decarbonising all of the platform power demands assuming Magnus would be reconfigured as a CCS hub as indicated during discussions with EnQuest. However, the specific details of this change of use and its effect on the potential to utilise the produced water, reconfigured wells or a cross-reservoir system needs further evaluation and study.

Based on the potential for Magnus and considering the wider potential for generating carbon free power from geothermal sources within the UKCS it is felt further studies would be worthwhile. Many of the characteristics found within Magnus that have limited the scope for increasing geothermal power on that platform may not be the case with others. The key characteristics to assess and look for would be high well temperatures, larger diameter well tubulars, availability of suspended wells or free well slots and less congested topsides.

2 Introduction/Background to the project

On 4th July 2022 a Directed Project Agreement was made between Net Zero Technology Centre Limited, CeraPhi Energy Limited and EnQuest Heather Limited to undertake a feasibility study looking at the potential to decarbonise the UKCS offshore hydrocarbon production.

Additionally, Petrofac was included in the Agreement as Industry Sponsor.



The Magnus oilfield is a large oilfield in the United Kingdom's zone of North Sea which was discovered in March 1974 by BP. It is located 160 kilometres (99 mi) north-east of the Shetland Islands. Similarly to several other fields in the area, the field was named after the Viking saint–Magnus of Orkney.

It is a four-legged steel structure with integral deck trusses. Each leg has a foundation of nine piles and is located in a water depth of 186 m. The Installation has provision for 28 platform wells and a number of subsea wells connected via flowline risers.

EnQuest acquired an initial interest in Magnus in 2017 and increased this to 100 % in 2018. Magnus still has significant potential, with 2C Resources of c.35 MMboe at the end of 2020, in addition to an estimated c.250 MMbbls of remaining mobile oil in place.

The feasibility study would use the Magnus platform as a basis to assess the potential of harnessing heat energy from non-producing wells using a new and novel closed-loop energy generation well system (the CeraPhiWell™) and from the produced water stream using direct heat exchanger technology. The heat energy would be converted into clean electrical power using Organic Rankine Cycle (ORC) generators.

To develop this concept, the Phase 1 feasibility study would determine the key elements required to develop this technology further, including a review of the existing well data and current platform infrastructure. It would determine the amount of heat available from existing wells and also consider the potential of installing new geothermal wells. The study would review the brownfield modifications necessary for the installation of ORCs. The output would be a high-level conclusion of the technical outcomes, along with proposals for the next phase.

The Project consists of seven work packages completed over a 6-month period, and the study was a desktop review only, with no offshore platform visits undertaken.

CeraPhi would like to acknowledge and thank EnQuest and Petrofac for their support and input into this report.

3 Project methodology (Work Packages)

The Project aimed to develop a solution that could reduce offshore carbon emissions from power generation by harnessing heat energy from non-producing wells and from produced water.

The main objective for this phase 1 study was to give a high-level scoping of the concept and provide a preliminary feasibility assessment of deep geothermal heat energy generation system from a non-producing well and the produced water stream.

The study comprised of seven work packages as outlined below:

- **Work Package 1**: Detailed review of use of existing heat from produced water stream for heat or power purposes, including brownfield modifications required to facilitate re-use.
- **Work Package 2**: Detailed review of the well infrastructure, history and any potential integrity issues and give a view on the feasibility of repurposing these wells.
- **Work Package 3**: Detailed review of well data to understand well thermal gradient / heat potential.
- **Work Package 4**: Detailed review of potential heat energy that could be available from the re-purposed wells.
- **Work Package 5**: Detailed review of the potential drilling of new CeraPhi wells and the potential heat energy that could be gained from a new well.
- **Work Package 6**: Detailed review of potential Organic Rankine Cycle (ORC) application for platform power generation, including brownfield modifications required to integrate any new facility into available footprint, structural constraints, and existing power infrastructure.
- **Work Package 7**: High level technical feasibility report that would detail preliminary design, timeline, potential risks, and potential emissions reductions benefit.

After the project had commenced, it was agreed to extend the scope of Work Package 4 by including a review of the potential heat energy if the reservoir were to be exploited using standard doublet (injection and producer wells) geothermal techniques.

- **Work Package 4a**: Review of potential heat energy from cross reservoir connectivity.

Following discussions with EnQuest the review of heat sources and the potential energy recovery was conducted in consideration of the three main phases of the platform lifecycle, these being:

1. Current operations
2. Cessation of Production and Decommissioning of oil production facilities
3. Potential future operations as centre for Carbon Capture and Storage

4 Review of heat sources

The following Work Packages cover the review of available sources of heat energy, both from the use of the produced water stream and from repurposing existing Magnus wells using CeraPhiWell™ technology. Other heat sources considered include new drill wells specifically designed for CeraPhiWell™ technology and cross-reservoir fluid flow using a traditional 'doublet' geothermal system.

4.1 WP 1: Detailed review of use of existing heat from produced water stream

EnQuest provided process data for Magnus's operations, and from that information it was concluded that 165,000 bpd of water is being produced with a temperature of 100 °C.

Two applications were identified for use, using the produced water as a heat source:

- Heat Integration on Magnus Platform
- Heat to power solutions through the application of an ORC unit. See Section 5 for further details.

Table 1 below shows the heat users identified on the Magnus platform and the resulting conclusions made from the review of whether the produced water would be able to provide the required heat for the process unit.

One of the primary process heating users on the platform is the glycol reboiler within the gas dehydration unit. The reboiler operates at 200 °C. The heat available from produced water is far less than 200 °C and therefore it is not feasible. The other heater in constant use is the fuel gas heater. As the fuel gas heater will also be required during start-up when produced water is not available; it is therefore not recommended to be modified.

An alternative arrangement may be to use electrical fuel gas heaters for start-up, and then switch to the use of produced water heat once normal production has been established. This would add complexity to operations for a marginal gain and is not recommended. Additionally, part heating of glycol with produced water stream to reduce fuel gas usage to heat glycol to 200 °C is not considered viable due to the added complexity on the platform as a result.

There are also two pipeline depressuring pre-heaters on the line to flare; these are used intermittently only and are on a safety critical system (line to flare). These units will be required in instances when produced water is not available so it is not recommended to replace these units.

Were changes to be made to these heaters, electric heaters would need to be swapped out completely and replaced, adding to the time and cost to carry out the modifications. Hence from both an economical and operational perspective, the brownfield modifications on Magnus are not viable when considering the little benefit gained from making any changes.

However, it should be highlighted that this analysis is specific to Magnus and it should not be interpreted that this strategy would not work on other assets – analysis for each asset would have to be taken into consideration before making conclusions regarding the potential of heat integration using the produced water.

For example, on assets that have encountered challenges with oil water separation and / or emulsions, it could be beneficial to pre-heat the production fluid stream using the produced water stream as the heating medium resulting in heat integration and separation at warmer temperature. This is not however required on the Magnus Platform.

As summarised in Table 1, it is not considered possible or practical to convert the current heat users to heat extracted from produced water.

The potential for power generation from the produced water system via an ORC unit is discussed in Section 5.

Table 1 Magnus Platform Heat Users

<table>
<tr><th>TAG</th><th>System</th><th>Name</th><th>Constant/ Intermittent</th><th>Duty</th><th colspan="2">Notes</th></tr>
<tr><td>E-1401 / 2401</td><td>Gas</td><td>Glycol Regenerator</td><td>Constant</td><td>TBC</td><td>The produced water being circulated comes out the wells at approximately 90 to 100 °C, and the Glycol Regenerator operates at a temperature of 200 °C.

The produced water is therefore incapable of providing the required heat to the Glycol Regenerator. Not recommended to make any alterations.</td><td rowspan="4">Electric Heaters would need to be swapped out completely and replaced with Heat Exchangers, adding to the time and cost to carry out the modifications.</td></tr>
<tr><td>E-6001</td><td>Flare Gas</td><td>Pipeline Depressurising Pre-Heater</td><td>Intermittent</td><td>TBC</td><td rowspan="2">As the Flare Gas system is in use for the Magnus platform operation, it is not recommended for the flare gas system to be modified to incorporate heat from the produced water system.</td></tr>
<tr><td>E-6004</td><td>Flare Gas</td><td>Pipeline Depressurising Pre-Heater</td><td>Intermittent</td><td>1.1 MW electric</td></tr>
<tr><td>E-7101 A/B</td><td>Fuel Gas</td><td>Fuel Gas Heater</td><td>Constant</td><td>TBC</td><td>Required for start-up operations when produced water would not be available.

Due to the ongoing operation of the Magnus platform, it would not be a cost-effective solution to re-purpose the Fuel Gas system to incorporate heat from the produced water.</td></tr>
<tr><td></td><td>HVAC System</td><td></td><td>Constant</td><td>TBC</td><td>HVAC systems will be required to run during production and when production is shut-in, produced water would not be available during upset or shut-in conditions. Not considered feasible to utilise heat for the hot air systems to plant and accommodation areas.</td><td></td></tr>
</table>

4.2 WP 2: Review of existing well infrastructure

EnQuest provided significant information relating to the life of wells on the Magnus platform including:

- Current well status diagrams
- Well integrity data
- Intervention history
  - Well intervention and integrity work summaries
- Key information outlining
  - Hold up depths (HUD)
  - Agreed actions / interventions including any proposed work scopes
  - Key risks in each well
  - Causes of and mitigations to risks

CeraPhi Energy reviewed the well data and analysed the intervention history and considered the key risks as well as any concerns regarding well integrity. From this data mining, individual wells were analysed to understand their current status and from this, conceptual designs formulated to maximise thermal recovery.

CeraPhi undertook an analysis of all the wells in respect to their construction and operational history, their well integrity and the current status of each well. Three of the 28 wells on Magnus were not reviewed due to conductor integrity issues that were deemed uneconomic to resolve.

Well schematics were created for the current configurations of the wells and from them, conceptual repurposed well design schematics were created. The new schematics included details such as completion tubing diameters, additional bridge plug depths and bottom hole assemblies for the CeraPhiWell™ system. All individual well data and CeraPhiWell™ schematics are shown in Appendix 9.2.

After creating the well schematics, the extensive dataset was reviewed to assess the well structural integrity of the 25 wells to identify which ones would be most suitable for repurposing from a structural integrity perspective. It should be noted that the integrity reviews are based on current well envelopes and have not considered production casing integrity.

The main aspects of the wells reviewed for suitability were, tubing and annular integrity including reviewing of any sustained casing pressures in the annuli. Tubing and casing hanger voids were also assessed, as well as the tubing integrity itself if calliper logging runs had been conducted.

From the individual reviews, the wells were then rated ‘Good’, ‘Average’ or ‘Poor’ based on their suitability.

11 of the wells were rated as Average, the reasons for these rating were mainly minor issues which could be resolved easily or would not affect performance when utilised for geothermal, such as they failed the 13-3/8” hanger void test. The other 14 presented no issues and were rated as Good.

Overall, in regard to structural integrity, all of the wells show good potential for repurposing based on information received, however further testing would be required before any work is done as things can still change while the wells are still in operation for the near future. This would include but not limited to calliper or acoustic/ultrasonic surveys of the production casing/liner as well as acceptable pressure testing of the proposed operating envelope to confirm suitable integrity.

The true vertical depths (TVD) of the 25 wells are all fairly similar, ranging from well M50 with a TVD of 2,943 m, to well M45 with a TVD of 3,452 m. The measured depths (MD) however vary considerably from a MD of 3,345 m as a nearly vertical well, to a MD of 7,628 m due to its directional profile.

In general, the deeper the well is vertically, the hotter the well gets, improving the potential geothermal output. Directional wells can also improve performance as it can mean longer residence time at the hotter temperatures particularly in longer lateral sections.

The casing and tubing diameters were required for WP 4 where hydraulic modelling for each of the wells calculated pressure losses at different flow rates, as this is an important aspect to potential heat recovery.

The production liners tend to be the main limiting hydraulic factor as these are the narrowest sections of the casing. Generally, the injector wells utilise a 7” production liner whereas producer wells generally have 5 ½” liners although there are also some with 4 ½” liners which stretch the limitations even further. However, it is possible that a CeraPhiWell™ design could be installed above these sections if they are relatively short in length and thus have minimal significant effect on the overall performance.

The intervention history for each well was used to determine the hold-up depths (HUD) of each of the wells. This was important to know as any limitations on the well which prevent the bottom being reached by the CeraPhiWell™ system would obviously restrict the hotter temperatures being reached and will affect performance.

The HUD (if there is one) was included on the individual well schematics.

4.3 WP 3: Review of well thermal gradient data

4.3.1 Geology

4.3.1.1 Stratigraphy

The overburden from seabed to reservoir consists of a layer cake stratigraphy while the reservoir is inclined to about 9 degrees and dips to the east. The following is a description of the stratigraphic section (Figure 1).

- **Nordland Group**: Generally, a mud dominated formation, with three sandy members that are correlatable across the Magnus area and deposited in a shallow marine setting.
- **Hordaland Group**: Mudstone dominated unit.
- **Rogaland Group - Balder Formation**: Tuffaceous mudstone that makes it a distinctive marker across the North Sea region with abundant tuff layers (particularly in the Lower Balder).
- **Rogaland Group - Sele Formation**: Hemipelagic, grey, laminated mudstone with some minor tuff and sandier layers and very thin in the Magnus area, around 5-20 m.
- **Lista Formation**: Green-grey, poorly laminated, bioturbated mudstone, with variable sand/silty intervals and limestone beds.
- **Shetland Group**: Comprises a thick sequence of mudstone with minor interbedded argillaceous limestones.
- **Turonian Sandstone Member**: Calcareous rich siliclastic package only encountered to the north of the field.
- **Cromer Knoll Group**: Marly unit that is dominated by mudstones, marls and limestone beds. It is generally very thin in the Magnus area, sometimes only a metre thick.
- **Upper Kimmeridge Clay Formation**: Mudstone dominated formation with high gamma readings making it a distinct marker in log interpretation.
- **Magnus Sandstone Member**: Main reservoir of the field described below in Section 4.3.1.2.
- **Lower Kimmeridge Clay Formation:** Second main reservoir of the field described in Section 4.3.1.2.

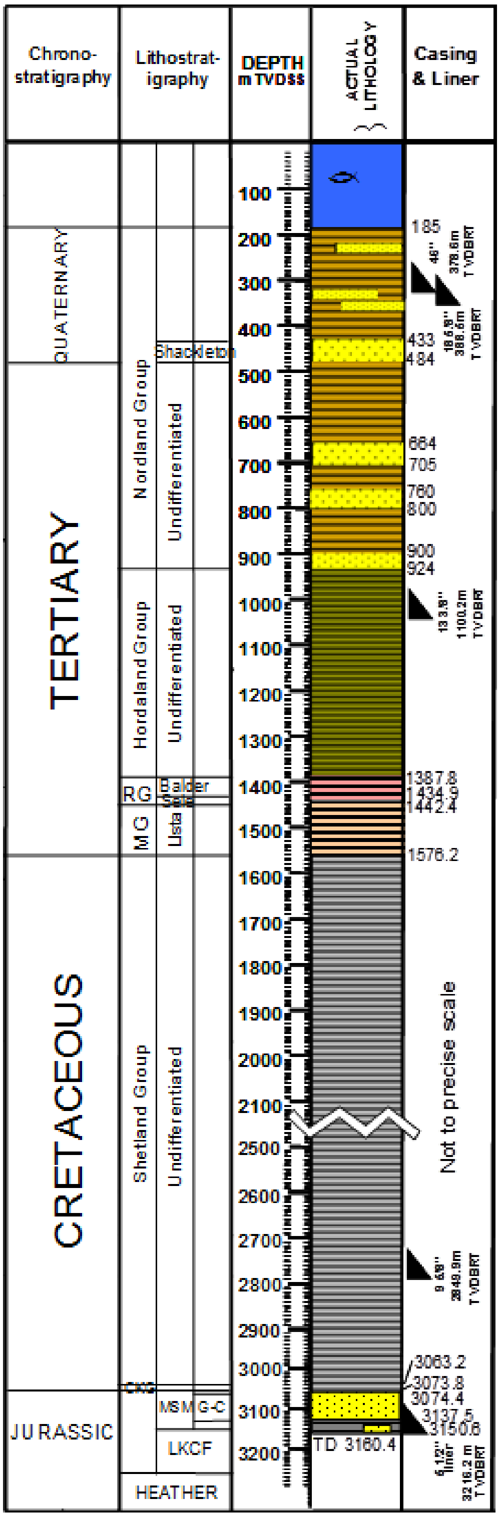


Figure 1 Magnus stratigraphic column

By examining the borehole records, we have arrived at the following generalised summary of the geological conditions in this area with emphasis on the thermal properties (Table 2 and Table 3).

Table 2 Summary of geological formations in the main area of the Magnus field

Group/Formation	Lithology/ Classification	K (W/m °C)	Thickness (m)	Depth TVD (m)
Undifferentiated Shallow Section	Sst 80% Mst 20%	2.25	155	0
Nordland Group	Mst 85% Sst 10% Lmst 5%	2.20	601	397
Hordaland Group	Mst 100%	2.10	473	998
Rogaland Group (Balder Fm.)	Mst 50% Tuff 45% Lms 5%	1.80	32	1471
Lista Formation	Mst 90% Lmst 10%	2.15	124	1503
Shetland Group	Mst 90% Lmst 10%	2.15	1227	1627
Cromer Knoll Group	Absent			
Magnus Sst. Member	Sst 80% Mst 20%	2.25	61	2854
Lower Kimmeridge Clay	Sst 50% Mst 50%	2.20	52	2915
Heather Fm.	Mst 90% Lst 10%	2.15	40	2967
Total Depth				3007

Table 3 Summary of geological formations in the North West area of the Magnus field

Group/Formation	Lithology/ Classification	K (W/m °C)	Thickness (m)	Depth TVD (m)
Undifferentiated Shallow Section	Sst 80% Mst 20%	2.25	154	0
Nordland Group	Mst 90% Sst 10%	2.15	625	396
Hordland Group	Mst 90% Lmst 10%	2.15	358	1021
Rogaland Group (Balder Fm.)	Mst 50% Tuff 45% Lms 5%	1.80	60	1379
Lista Formation	Mst 90% Lmst 10%	2.15	142	1439
Shetland Group	Mst 90% Lmst 10%	2.15	1314	1582
Turonian Sandstone Member	Mst 90% Sst 10 %	2.15	29	2895.3
Base Cretaceous Unc.	Mst 90% Lst 10%	2.15	2	2924
Heather Fm.	Mst 90% Lst 10%	2.15	43	2926
Brent Group (Tarbert Fm.)	Sst 100%	2.30	25	2969
Brent Group (Rannoch Fm.)	Sst 50% Mst 50%	2.20	37	2994
Dulin Group	Mst 100%	2.10	72	3031
Total Depth				3103

4.3.1.2 The Magnus reservoirs

The Magnus reservoirs, in the main field area, are composed of Late Jurassic turbidite sands deposited in the submarine fans of the Magnus Sandstone Member (MSM) and Lower Kimmeridge Clay Formation (LKCF), derived from the East Shetland plateau to the west. The Magnus reservoirs in the North West portion of the field are the Tarbert and Rannoch Fms., which are part of the Brent Group. These deposits are Middle Jurassic deltaic shallow marine sandstones. Figure 2 shows the Magnus field extension and Figure 3 presents the generalized stratigraphic column for a typical well in the field.

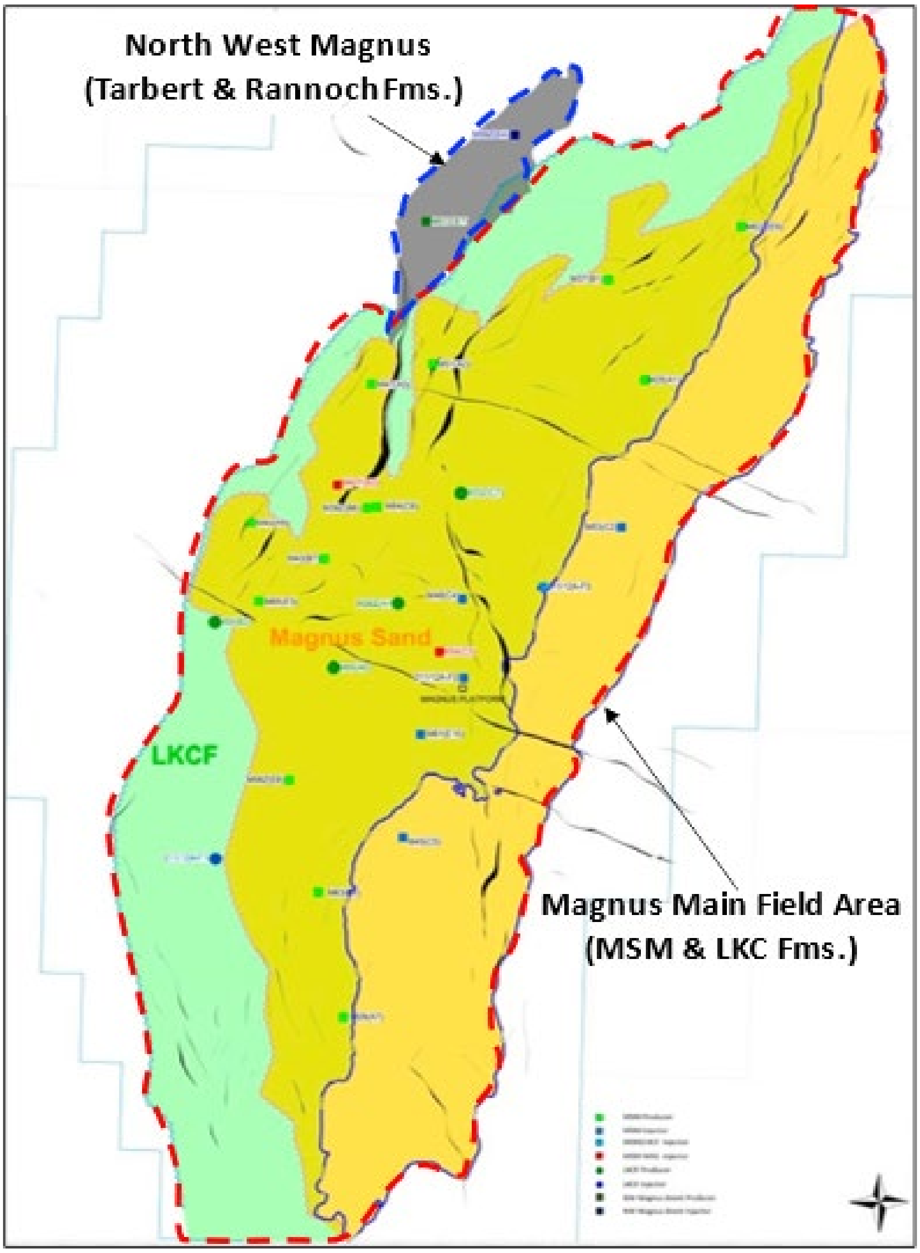


Figure 2 Magnus field extension

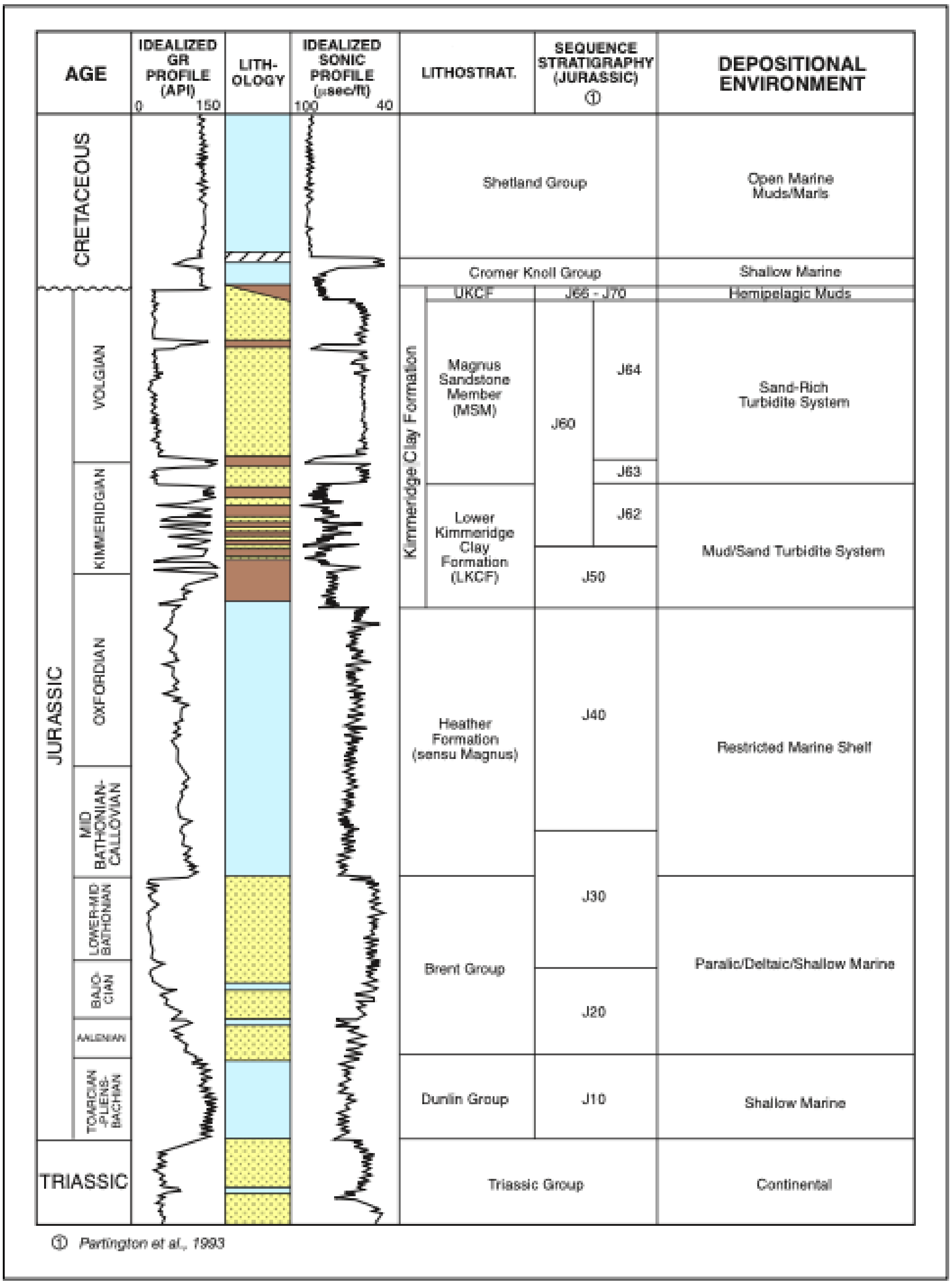


Figure 3 Stratigraphy, wireline logs, lithology and depositional environments for an idealised Jurassic succession in the Magnus field (Morris et al., 1999)

The three major reservoir units have the following general characteristics:

- The MSM is a high net-to-gross sequence dominated by thick-bedded fine-to-coarse grained sandstone units. The sandstones are amalgamated unconfined turbidites with 20-30 m-thick units interbedded with 1-5 m-thick shales (N:G of 85 %, Total Thickness: up to 220 m). Porosities are 18-24 % and permeabilities up to 2000 mD, with a geometric mean 85 mD. The sandstones are fine to coarse grained and variably sorted. Diagenesis influences the reservoir quality, especially in the water leg, in which Illite in the pore space preserves porosity but compromises permeability.

- The LKCF is a lower net-to-gross reservoir sequence (average 35 %) dominated by well laminated, hemipelagic to turbiditic mudstones, debris flow units and turbiditic sandstones. Porosities are 12-24 %. The lateral connectivity is poor; however, it improves towards the crest at the center of the field, in which N:G could be up to 65%.

- The Brent Group formations are mainly deltaic shallow marine sandstones deposits. Most of the reserves are contained in ~25 m net sandstone of the Tarbert Fm. This Fm. has a N:G of 80 % and average porosities of 22 %.

4.3.1.3 Structural configuration of the field

The configuration of the field is a south-easterly dipping tilted fault block and its lateral extent is defined both stratigraphically and structurally. Reservoirs are wedge-shaped and stacked, with pinch out up-dip north and multiple cycles down-dip south from the crestal region (Figure 4).

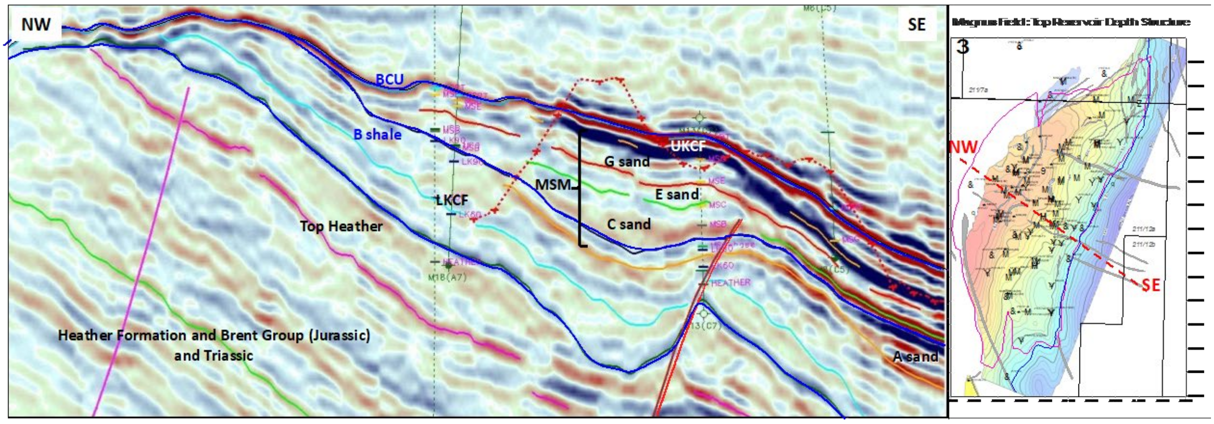


Figure 4 Magnus seismic dip section

Erosional truncation of the easterly dipping reservoir units forms the western field boundary. The MSM and LKCF surfaces intersect the oil-water contact to form the eastern field limit that originally was located at 3160mSS True Vertical Depth (TVDSS).

4.3.2 Geothermal Gradient

Estimated geothermal gradients for each well were then added to the well schematics. For each well all the temperature data available was gathered from multiple sources, among them data from permanent monitoring system (gauges) included in the intervention history, well log headers (LWD and WL), formation pressure surveys, cementing reports, drilling and geological EORs, composite logs, well programs, etc., with their corresponding depths. From this a guide to the geothermal gradient could be calculated for each well and then extrapolated to find the bottom hole temperature. No Horner plots were performed, and it is accepted that dynamic temperature data would underestimate roughly 10-15 % of the static reservoir temperatures.

The geothermal gradient varies greatly across the 25 wells in the Main Magnus field area, with Well M48 having the lowest at 34 °C/km and Well M43 having the highest with 48 °C/km. The estimated gradient in the main area of the Magnus field is 40 °C/km (Figure 5), this gradient was estimated considering a linear gradient between the mud line at 242 m TVDBRT (185 m TVDSS) with 4 °C and the different BHTs at different depths. In the North West Magnus area, only two data points from two wells were used, the area conforms to a linear geothermal gradient of 43°C/km (Figure 6). The NW area of Magnus seems to possess a slightly higher gradient than the Magnus main area as reported in various EOWRs, however the data evaluated is limited.

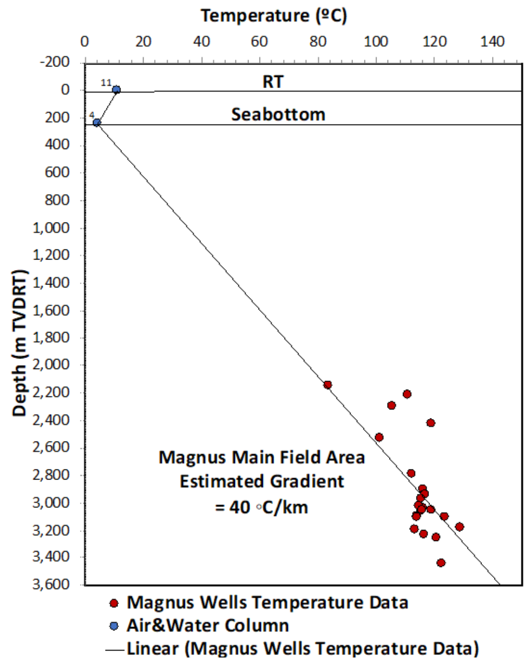


Figure 5 Magnus main field area temperature profile

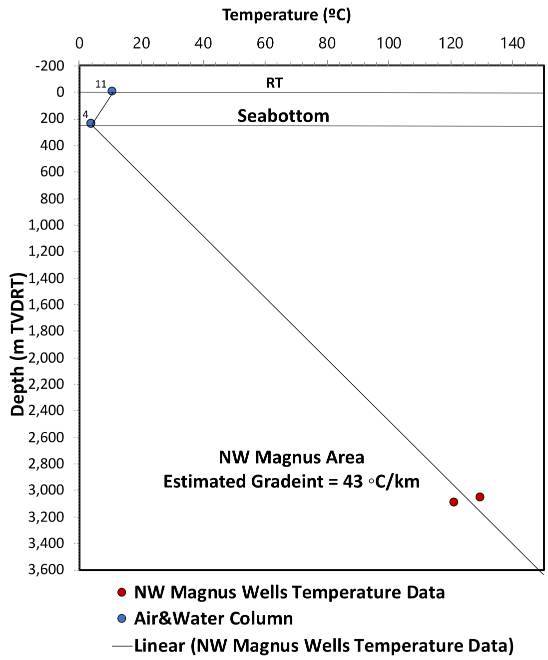


Figure 6 North West Magnus area temperature profile

4.4 WP 4: Review of heat energy available from re-purposed wells

From the well information complied in Work Package 2, thermodynamic and hydraulic analysis was undertaken on the recommended configurations to see what geothermal potential the wells have.

The first step was to run hydraulic calculations. As mentioned earlier in the report, this is vital as it determines the range of fluid flow rates that are technically and economically feasible within the well. Faster flow rates are generally good as that increases the thermal energy recovered, however increasing flow rates also increases the pressure losses in the well due to the friction between the tubing and the flowing fluid. Increased pressure loss means more pumping power is required which increases the system parasitic load and decreases the overall potential output power and also comes at a higher operating cost along with higher initial CAPEX for larger pump and motors. The pressure losses can be reduced by altering other parameters for example tubing material or the circulation fluid used.

The hydraulic calculations were run using three different material tubulars (standard steel, Vacuum Insulated Tubing (VIT), and steel with insulating coating) and at different flow rates (Table 4). Initial high-level calculations showed that anything over 10 litres per second (l/s) for the majority of the wells would create far too much friction and would therefore be questionable in their viability. Further hydraulic and thermodynamic calculations were then run at 5 and 10 l/s for each well using the three different types of tubulars with varying levels of insulation.

As the different tubulars have different diameters, this also contributes towards friction losses. The more insulation a tubing has, the larger the overall diameter of the CeraPhiWell™ completion will be, which will create more friction on the cold fluid being pumped down outside the tubing, however, more insulation will result in higher temperatures being returned to the surface.

Table 4 Example of calculations

MD (m)	7200
TVD Depth (m)	3010
Internal Coating	None
External Coating	None
Process Fluid	Freshwater 25°C
Geothermal Gradient (°C/km)	40.6
Flow Rate (l/s)	5
Cp or Cv	Cv
Tubing Size (")	4 1/2
Tubing Weight (ppf)	VIT
Casing Size (")	7
Casing Weight (ppf)	32

Pressure drop accurate to +/-5%

Total Pressure Drop	9.03	Bar
Estimated Temp at Surface	104.11	°C
Bottom Hole Temp	122.21	°C
Temp Loss	18.09	°C
Temp Loss (%)	14.81	%
Pumping Power Requirement	5	kW

Flow Area			
	Area mm²	Area m²	Velocity m/s
Tubing	6207.34	0.0062	0.805498111
Annulus	8556.71	0.0086	0.584337003

Pressure Drop Split	
Pressure Drop Tubing (bar)	5.55
Pressure Drop Annulus (bar)	3.44
Pressure Drop Couplings (bar)	0.04

Tubing/Annulus Ratio	0.73

MD (m)	7200
TVD Depth (m)	3010
Internal Coating	None
External Coating	None
Process Fluid	Freshwater 25°C
Geothermal Gradient (°C/km)	40.6
Flow Rate (l/s)	10
Cp or Cv	Cv
Tubing Size (")	4 1/2
Tubing Weight (ppf)	VIT
Casing Size (")	7
Casing Weight (ppf)	32

Pressure drop accurate to +/-5%

Total Pressure Drop	33.11	Bar
Estimated Temp at Surface	112.58	°C
Bottom Hole Temp	122.21	°C
Temp Loss	9.62	°C
Temp Loss (%)	7.88	%
Pumping Power Requirement	33	kW

Flow Area			
	Area mm²	Area m²	Velocity m/s
Tubing	6207.34	0.0062	1.610996222
Annulus	8556.71	0.0086	1.168674005

Pressure Drop Split	
Pressure Drop Tubing (bar)	20.46
Pressure Drop Annulus (bar)	12.50
Pressure Drop Couplings (bar)	0.15

Tubing/Annulus Ratio	0.73

Along with the hydraulic calculations, high level thermodynamic calculations were run to estimate best case scenarios in regard to the fluid temperature expected at the well outlet (temperature at the wellhead after the fluid has completed its circulation down hole). This was estimated by calculating expected fluid heat loss from the bottom of the well to the top based on the level of insulation the tubing has and the heat conduction through the tubing to the cold fluid in the annulus. From the set of results, an optimum combination of tubing material flow rate was selected, this being VIT due to its very high insulating ability and 5 l/s. The estimated well outlet temperature for each well was added to the summary shown in Table 5.

A majority of the wells have very good thermal energy recovery potential. The average well outlet temperature is 111°C, which is at the lower end of the range required for power generation. Using the estimated temperatures and optimum flow rate (5 l/s), the thermal energy recovery from the well can be calculated using the below equation.

$$MWt = \frac{Cp\ x\ \dot{m}\ x\ \Delta T}{1{,}000{,}000}$$

Where:

- MWt = Thermal Energy output rate (MW)
- Cp = Specific Heat Capacity of Fluid (J/kg°C)
- $\dot{m}$ = Mass Flow Rate (kg/s, assumed equal to l/s for water)
- ΔT = Well Outlet Temperature – Well Inlet Temperature (°C)

Some of the more restricted wells showed high-pressure losses at the optimum flow rate, so it is likely that a slower rate would be required for this small percentage, which in turn would affect the thermal output. Likewise, some of the wells showed miniscule pressure losses so could potentially utilise a higher flow rate to increase the output. However, at this stage of the study the optimum flow rate of 5 l/s and temperature difference (ΔT) between well outlet and inlet of 20 °C (generic value for an ORC) was used to calculate the thermal output.

It is estimated that each well could potentially provide approximately 440 kW of thermal energy, combining to generate a total of **11 MW** gross thermal energy. It should be noted that this output is based on exclusively using closed-loop technology on the 25 active wells that are on the Magnus platform. A detailed review of exploring an open-loop / cross-reservoir system can be seen below in Section 4.5 of this report.

Table 5 Magnus Well data set estimated surface temperatures recovered to surface

Well TD (m)	Temp Reading (°C)	Temp ref depth TVD (m)	Geothermal Gradient (°C/km)	HUD MD(m)	Production Casing	Production Liner	TD TVD (m)	Estimated Temp at TD TVD (°C)	Estimated Well Outlet Temp (°C)
5376	119	3054	38	5219	9-5/8"	7"	3159	123	115
5265	116	2900	39	5138	9-5/8"	5-1/2"	2997	120	111
5029	117	2941	38	4907	9-5/8"	5-1/2"	3072	122	114
3501	119	2427	47	3395	9-5/8"	7"	3243	159	146
4516	101	2529	38	4358	9-5/8"	5-1/2"	2992	119	110
3564	116	3040	37	3488	9-5/8"	5-1/2"	3098	118	108
5585	124	3107	39	5495	9-5/8"	5-1/2"	3210	128	118
6300	115	2966	37	6115	9-5/8"	5-1/2"	3067	120	109
4613	113	2847	38	4443	9-5/8"	5-1/2"	2943	118	112
4459	116	3052	37	4380	9-5/8"	7"	3051	116	105
5102	117	3235	35	4930	9-5/8"	5-1/2"	3231	117	104
4469	112	2948	37	4227	9-5/8"	5-1/2"	3103	118	84
4311	111	2216	48	NO ACCESS	9-5/8"	5-1/2"	2950	148	126
4360	114	3100	35	4140	9-5/8"	7"	3328	122	111
3572	121	3256	36	3494	9-5/8"	7"	3293	128	126
3680	113	3194	34	3050	9-5/8"	7"	3250	115	106
4106	123	3440	35	4003	9-5/8"	7"	3452	123	112
4461	116	3057	37	4270	9-5/8"	5-1/2"	3155	119	112
4648	106	2295	44	4445	9-5/8"	4-1/2"	3164	144	126
3345	97	3249	29	3279	9-5/8"	7"	3247	97	90
4350	84	2148	37	4350	9-5/8"	5-1/2"	2978	116	111
7574	121	3093	38	4140	9-5/8"	5-1/2"	3102	121	107
6923	130	3060	41	5558	9-5/8"	5-1/2"	3057	130	106
3978	115	3020	37	3920	9-5/8"	5-1/2"	3052	116	110
7628	129	3177	39	7490	9-5/8"	4-1/2"	3176	129	104

4.5 WP4a Review of potential heat energy from cross reservoir connectivity

In this chapter we included an alternative to the CeraPhiWell™ (closed loop), employing a cross-reservoir (open loop) geothermal system. This would utilise the existing reservoirs and connectivity between the injector and producer wells from a geothermal perspective as opposed to hydrocarbon extraction. Consequently, this option would only take place post decommissioning. The different sections in this chapter refer to:

- 4.5.1 First, description of the reservoir connectivity with emphasis in MSM.
- 4.5.2 Second, high-level volumetric estimate of the MSM. We provided the Heat in Place (HIP) and Potential Power output (P) of a hypothetical plant considering whole MSM reservoir, excluding the number of injectors / producers and mas flow rate.
- 4.5.3 Third, in this case the evaluation of thermal output has taken into account the current wells for a hypothetical open loop system, considering the total number of injectors / producers and mas flow rate in the different sectors of the field.

4.5.1 Reservoir connectivity

The reservoir connectivity of the MSM is complex. The reservoir is compartmentalized by intraformational mudstones and listric faults that are fully or partially sealing due to clay smearing along fault planes. These listric faults, which are typically 1 km long, have throws of ~30 m and appear to flatten out near the base of the reservoir. Lateral connectivity is excellent in some areas, but is compartmentalised elsewhere by partially sealing faults and depositional pinchout of some flow units.

The LKCF is highly interbedded and lateral connectivity is challenging, however crestal areas with higher net/gross due to bed to bed amalgamation have more connectivity. It comprises deep marine low density turbidite and hemi-pelagic sequences, dominated by mud but with significant coarser sand units locally well developed. Although sand bodies are much thinner and less laterally continuous than in the overlying Magnus Sandstone Member, they are otherwise very similar and of equal reservoir quality.

For the Brent Group in the NW Magnus area, the main target reservoir is the Tarbert deltaic sandstones which can reach high net/gross and good reservoir properties.

Due to the limited lateral connectivity of the LKCF, it is not recommended at this point to use this formation as geothermal target. The Tarbert and Rannoch Formations. would be potential geothermal targets due to the apparent enhanced geothermal gradient in in the NW Magnus area. However, at this point of the preliminary study and the limited data evaluated it was decided to leave evaluation of these formations for further studies. Extensive lateral connectivity of the MSM and the data availability makes this reservoir the best geothermal target candidate for the cross-reservoir connectivity evaluation.

In the current Magnus EnQuest reservoir model no sector models are defined because all areas and layers of Magnus Main field are connected in some degree. However, in particular sectors, the level of baffling is severe enough to sustain pressure differences of several thousand psi for many years.

4.5.2 High-level probabilistic volumetric analysis

The volumetric method for assessing geothermal resources

For this evaluation the 3DHIP-Calculator created by Piris, et al. 2022 was used. The volume method involves the calculation of the thermal energy contained in each volume of rock and water. The software utilizes probability distributions functions (PDF) to define the input parameters and calculations are performed using the Monte Carlo method. The Heat in Place (HIP) can be computed by using the below equation defined by Muffler and Cataldi (1978).

$$HIP = V \cdot [\emptyset \cdot \rho_F \cdot C_F + (1 - \emptyset) \cdot \rho_R \cdot C_R] \cdot (Tr - Ti)$$

Where:

- V is the cell or voxel volume [m^3]
- $\emptyset$ is the porosity [parts per unit]
- ρ is the density [kg/m^3]
- C is the specific heat capacity [kJ/kg·°C]
- Tr is the cell or voxel temperature (reservoir temperature) [°C]
- Ti is the reinjection temperature [°C]
- the subindex ‘F’ or ‘R’ indicates fluid and rock, respectively.

In this case, the HIP was calculated for an idealized reservoir defined only by one cell. The reservoir was simulated with a constant volume of 3.5·10 m^3 (a surface of 35 km^2 by a 100 m thickness, corresponding to the extension of the MSM up to the original oil water contact and the average thickness of the MSM reservoir). The extension of the MSM aquifer is considered much larger, however was considered appropriate to constrain the evaluation to the extension of the field where the reservoir properties are known from the multiple wells drilled. Table 6 below shows the different input parameters used running 15,000 simulations.

Table 6 Parameters and values used for the simulation and calculation of the HIP. For Triangular distributions the values are ordered by Lower/ Most Probable/ Upper and for Normal distributions by Mean/ Standard Deviation.

Parameter	PDF	Values
Porosity	Triangular	0.18 / 0.21 / 0.24
Fluid Density (kg/m^3)	Triangular	951 / 958 / 966
Fluid Specific Heat Capacity (kJ/kg °C)	Triangular	3.81 / 3.84 / 3.87
Rock Density (kg/m^3)	Triangular	2300 / 2500 / 2700
Rock Specific Heat Capacity (kJ/kg °C)	Triangular	0.80 / 0.85 / 0.90
Reservoir Temperature (°C)	Normal	132 / 4
Reinjection Temperature (°C)	Fixed	95

The following plots are the results of the calculations showing a histogram with the HIP values in Petajoules (PJ) (Figure 7) and the cumulative probability curve of the HIP for the selected target and depth range (Figure 8), highlighting the P10_HIP (probability 10% of very low confidence of the estimation and high values), P50_HIP and P90_HIP (50% and 90% respectively indicating high confidence of the estimation and low values). The estimated HIP values are **271.3**, **316.9** and **362.6 PJ**, for **P90**, **P50** and **P10**, respectively.

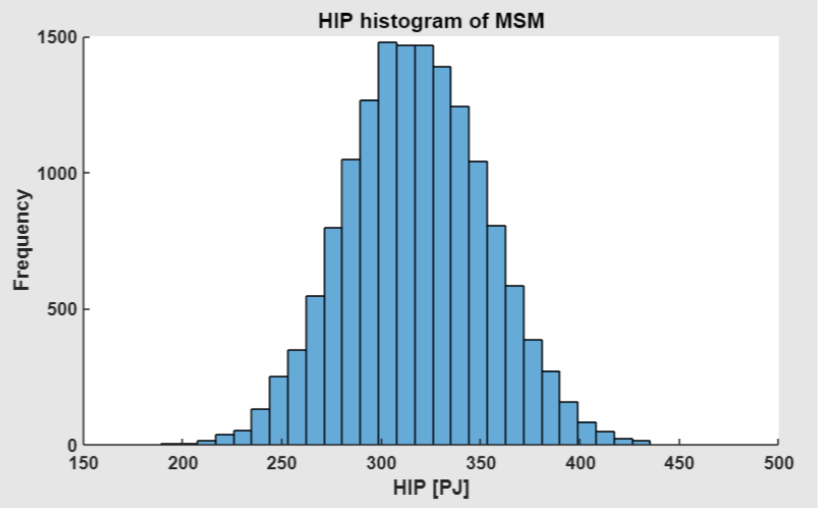


Figure 7 HIP frequency histogram

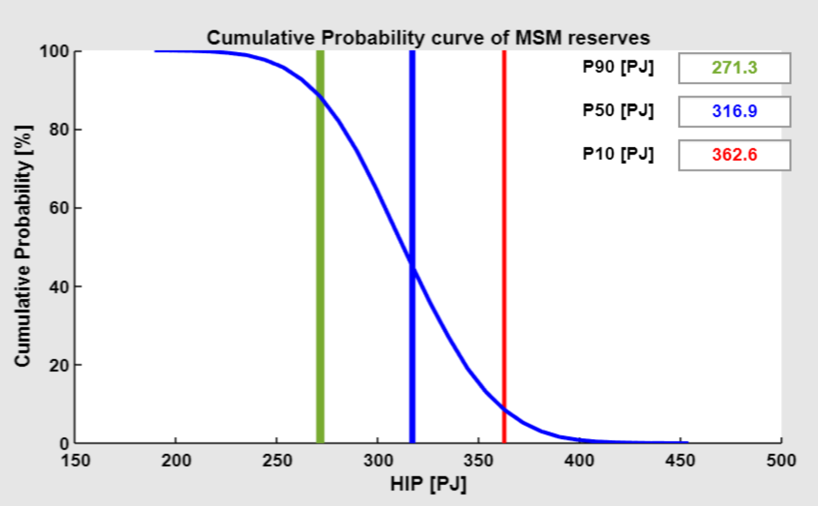


Figure 8 HIP cumulative probability curve

The above calculations only provide the total thermal energy in place in the reservoir (HIP). As a preliminary assessment, and in case of an ORC application from a low temperature geothermal reservoir, to size the Power Potential (P) of the power plant that could be supported by the resource, the following equation is further introduced in order to provide a high-level estimate.

$$P = \frac{HIP \cdot Rf \cdot Ce}{Pf \cdot Tlive}$$

Where:

- P= Power potential (MWe)
- Rf = Recovery factor [parts per unit]
- *Ce* = Conversion efficiency [parts per unit]. It considers the heat exchange efficiency from the geothermal fluid to a secondary fluid in a thermal plant
- Pf = Plant factor is the plant or load factor [parts per unit]
- *Tlive* = The mean plant lifetime or total project live [seconds]

Due to the fact the Piris, et al., 2022 does not provide a probabilistic estimate of the Power Potential for single cell models as ours, a deterministic approach has been applied using the percentiles computed in the HIP (P10_HIP, P50_HIP and P90_HIP) as Lower/ Most Probable/ Upper applying above formula. Table 7 below shows the different input parameters used.

Table 7 Parameters and values used for the deterministic calculation of the Power Potential of the Plant (MWe)

Parameter	Values
Recovery Factor (parts per unit)	0.10 / 0.15 / 0.25
Conversion Efficiency (parts per unit)	0.08 / 0.10 / 0.12
Plant Factor (parts per unit)	0.85 / 0.95 / 0.97
Plant Lifetime (Seconds)	946,100,000 (30 years)
HIP_P90 / HIP_P50 / HIP_P10 (PJ)	271.3 / 316.9 / 362.6

The parameter with more uncertainty of the evaluation is the Recovery Factor (Rf). Electricity generation potential depends on thermal recovery factor and currently little data exists on thermal recovery from brines in sedimentary basins because recovery factors for geothermal cases are rarely published.

Recovery factor refers to the fraction of the stored heat in the reservoir that could be extracted to the surface. It is dependent on the fraction of the reservoir that is considered permeable and on the efficiency by which heat could be swept from the reservoir. In this case the values chosen were based in the fact that the evaluated reservoir possess a known good quality, supported by production data over the years by using well injectors which effectively have swept the reservoir. However, the values chosen were preferably low due to the fact that the injection could eventually lead to eventual thermal breakthrough and the recovery factor should contemplate this.

The Power Potential (P) estimated for a hypothetical power plant, excluding the number of injectors / producers and mass flow rate and just for the reservoir as whole, was determined **3 MWe**, **5 MWe** and **12 MWe**, for the cases Low, Most Likely and Upper, respectively.

Volumetric estimation is most commonly applied during the early stage of a geothermal field development (HIP + Power Potential). However, because of the limited data and uncertainty on the assumptions on reservoir parameters i.e. Recovery Factor (Rf), some degree of cautiousness and conservatism are also inputted.

4.5.3 Evaluation of thermal output from the current wells (open loop system)

The evaluation of the thermal output from the current wells was performed from the information received from EnQuest, as the assumption could be made that the fluid flow rate (oil & water) would be similar to the current extraction rate and then combine this with the estimated returning temperatures calculated using closed-loop technology in section 4.4.

The 25 wells were then split into the respective sectors, as reported in the well connectivity diagrams reported in the Magnus Well Book 2022. The current oil and water flow rates were added. The minimum values are considering the well with lowest flow rate per sector, and if only this well is producing, and the maximum is the sum of all the wells producing in each sector. The well head flowing pressures were extracted from the Magnus Well Information Pack of 2021.

Using the same method to determine the thermal output from the closed loop wells, the potential output when utilising cross-reservoir open loop geothermal system was calculated. Table 8 shows the output of each sector in the field, this is based on an average of the flow rates that each well in the sector is currently flowing at.

Table 8 Thermal output for each field sector

Sector	Most Likely Thermal Output (MW)
CENTRAL MSM (A)	4.14
SOUTHERN MSM	4.75
NORTHERN MSMS	3.17
A3B3	0.62
LKCF	1.58
NW MAGNUS BRENT	1.5
Total	**15.76**

As open loop geothermal is much more complex than closed loop to model accurately, this is only a high-level estimate. Without detailed knowledge of the reservoirs and flow characteristics, it is difficult to accurately predict how the circulation fluid will flow through the reservoirs and how much heat will be extracted. This estimate is also based on current flow rates which likely would change when repurposing for geothermal which could improve thermal output.

4.6 WP 5: Review of the potential drilling of new CeraPhiWell™

In the previous WP4 section, the energy potential of installing a downhole co-axial closed-loop heat exchanger in existing O&G wells on the Magnus platform was estimated. This section has evaluated the potential of drilling a new closed-loop geothermal well. The proposed new well is a 4,000 m TVDSS deep well with a 9 5/8'' production casing / liner reaching a bottom hole temperature of approximately 190 °C.

As all the Magnus well slots are fully used, there is no available space for a new geothermal well to be drilled. Initial consideration was given to drilling a sidetrack from the current wells to install a new CeraPhiWell™, however this sidetrack would most likely come from the 9-5/8" casing and the resulting CeraPhiWell™ production casing would at best be 7-5/8".

This would be slightly larger in size to the repurposed wells and may result in a limitation on flow rates and heat recovery although furthermore detailed review of this could be considered. Hence this review is to show the potential difference between a repurposed and new drill well in case space could be made available in the future.

If a new well was to be considered, then the thermal recovery could be optimised by designing the well specifically for a CeraPhiWell™ system rather than for targeting specific hydrocarbon zones.

Based on using similar geothermal gradient and depths as the other wells, the well outlet temperatures below are obtainable for a period of 30 years. An increased flow rate can be used as the completion can be sized to suit and to reduce frictional pressure drops.

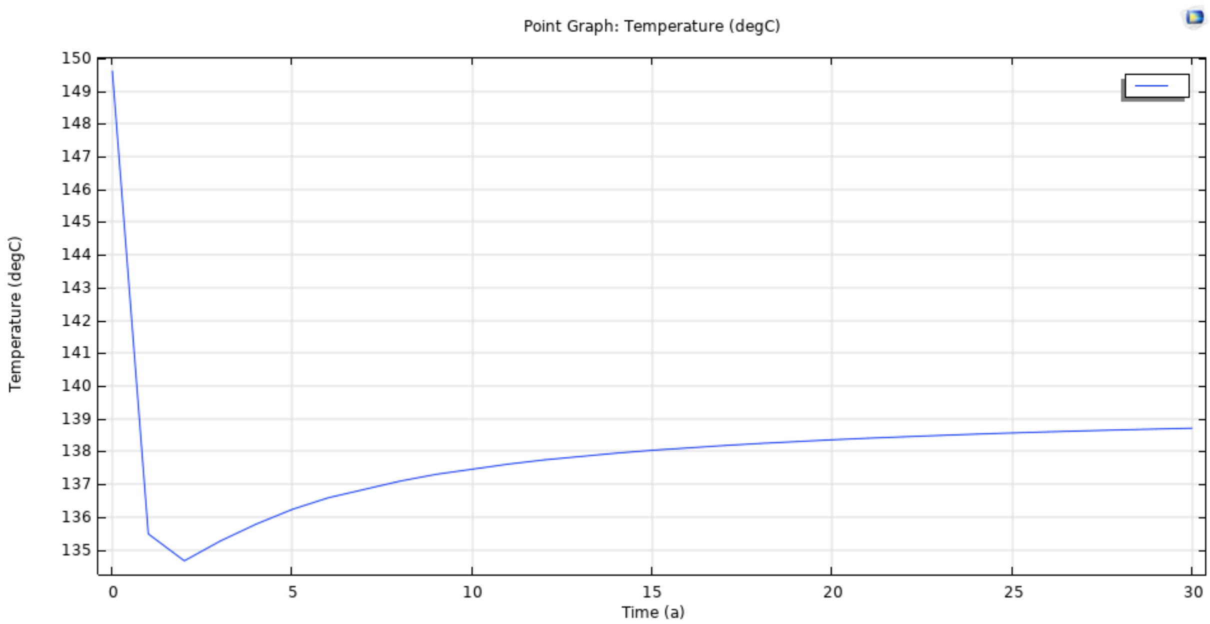


Figure 9 Well Outlet Temperature over 30 years based on ΔT of 20°C, flow rate of 20 l/s

By allowing a flow rate of 20 l/s, this increases the thermal energy output from the well from less than 400 kW estimated for the original wells to 1.6 MW for the specifically designed well.

As can be seen in Figure 9 Well Outlet Temperature over 30 years based on ΔT of 20°C, flow rate of 20 l/s the initial outlet temperature drops rapidly in the first couple of years, however as the fluid being injected back into the inlet is still hot (100 °C+), this heats up the upper section of the well which causes the outlet temperature to slightly increase again.

It is important with geothermal energy to carefully manage the available thermal energy in the wells by balancing the ΔT and flow rate. Although the higher flow rates and ΔT provide a much higher thermal output, it depletes the available thermal energy much quicker, meaning the high temperatures that are initially possible, soon decrease (as shown by the steep initial decline in temperature in the first couple years in Figure 9). Therefore, it is vital to find the correct balance of ΔT, flow rate, and well outlet temperature. One possible way of achieving this is by managing extraction between several wells in order to allow the resource to recharge naturally over specific time periods.

5 WP 6: Review of Organic Rankine Cycle Technology for power generation

The following work package entails the review of Organic Rankine Cycle (ORC) technology to convert available low-grade heat into useable electricity on the Magnus Platform. In line with the work in the earlier sections, three different cases have been identified:

1. Produced Water: The produced water is routed to a heat exchanger to recover heat, which is converted to electrical energy by the ORC package.

2. Closed Loop: Wells are repurposed and well circulation fluid is circulated through the downhole heat exchanger at the bottom of a depleted production well to recover geothermal energy which is converted to electrical energy by the ORC package.

3. Open Loop: Fluid is injected into a typical injection well and is passed through bedrock to another depleted production well which acts as a source well for the fluid returning to the surface. The temperature rise in the fluid originates from the flow through the bedrock however this also results in the entrainment of oil, gas and sand which needs to be separated after the fluid leaves the source well. Heat is then recovered and converted to electrical energy by the ORC package.

5.1 Organic Rankine Cycle Technology

Traditionally, in large-scale power generation, steam cycles are the preferred solution for heat recovery and external combustion of solid and heavy fuels, while internal combustion engines are the usual choice for clean and standard liquid or gas fuels. Still there is a large variety of energy sources, with limited temperature and/or thermal power available, for which gas and steam cycles are not a convenient choice.

Organic Rankine Cycle (ORC) technology is like a traditional steam turbine, but with a single, important difference. Instead of using water vapour, the ORC system vaporizes a high-molecular-mass organic fluid, resulting in excellent electric performance and several key advantages: slower turbine rotation, lower pressure and no erosion of metallic parts and blades. Organic Rankine Cycles have proven to be a technically and economically valuable solution, offering high performance, flexibility, and low capital costs.

ORC systems are used for power production from low to medium temperature heat sources in the range of 80 to 350°C. This technology allows for the exploitation of low-grade heat that otherwise would be wasted. The working principle of an ORC power plant is like the most widely used process for power generation, the Clausius-Rankine Cycle. The main difference is the use of organic substances instead of water (steam) as a working fluid. The organic working fluid has a lower boiling point and a higher vapour pressure than water and is, therefore, able to use low temperature heat sources to produce electricity. The organic fluid is chosen to best fit the heat source according to their differing thermodynamic properties, thus obtaining higher efficiencies of both cycle and expander.

The main components of an ORC system power plant design are:

- The Turbine – This is the key component of the entire ORC power plant and determines the ORC system performance. It expands the working fluid producing mechanical energy that is converted into electricity by a generator coupled with the turbine shaft.

- The Heat Exchangers – The working fluid flows through the heat exchangers, extracting the heat from the heat source. Shell and tube heat exchangers are usually applied but the geometry and configuration are varied depending on the energy source and the total thermal input.

- The Condenser – With the direct air or water to fluid heat exchanger, the organic fluid is cooled and liquefied before entering the pump. The use of cooling water reduces the topsides footprint of the equipment; however, it is possible to also use an air-cooled condenser.

- The Feed Pump – Brings the organic fluid from the condensation pressure to the maximum pressure of the Organic Rankine Cycle. The pump is usually driven by an electric motor at variable rotating speed.

The following schematic (Figure 10) presents an example of a generic ORC flow diagram and corresponding temperature vs. entropy chart with the points on the cycle plotted. The ORC turbogenerator uses a medium-to-high-temperature source to preheat and vaporize a suitable organic working fluid in the evaporator. The organic fluid vapour rotates the turbine, which is directly coupled to the electric generator, resulting in clean, reliable electric power.
The turbine outlet vapour flows through the regenerator, where it heats the organic liquid and is then condensed in the condenser and cooled by the cooling circuit. The organic working fluid is then pumped into the regenerator and evaporator, thus completing the closed-cycle operation.

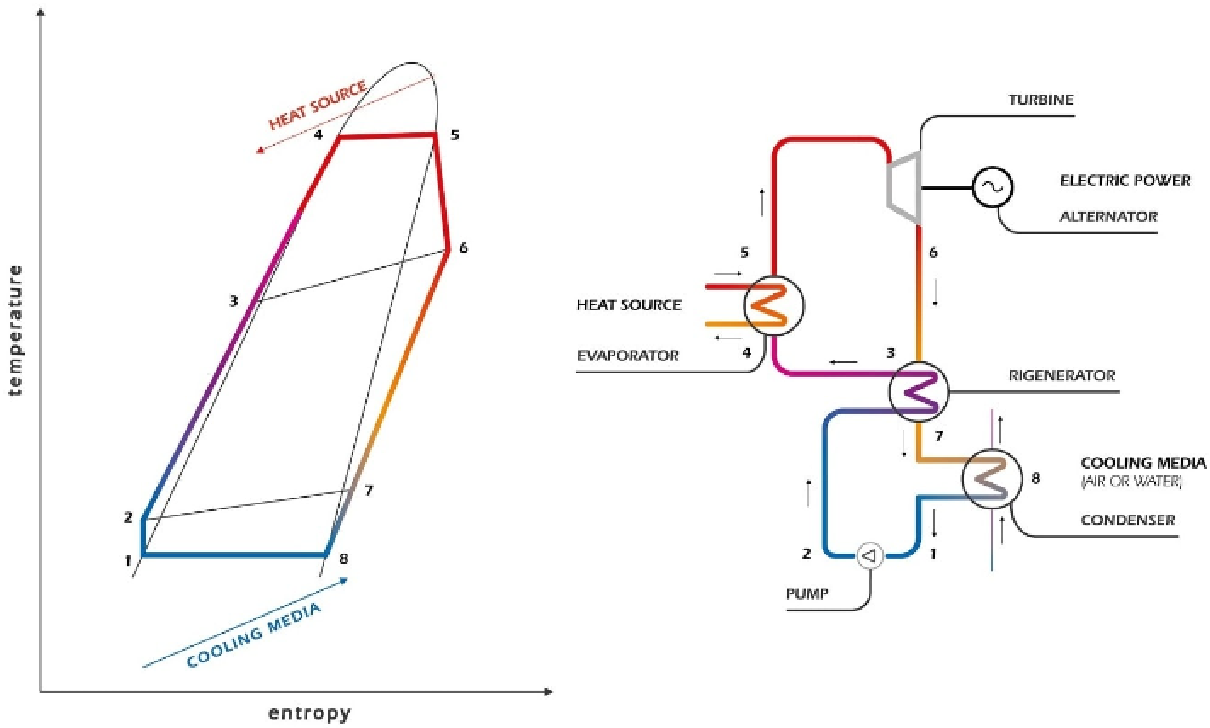


Figure 10 ORC Cycle – Generic Temperature vs Entropy Graph (Reference – Turboden)

By converting thermal energy to electricity at low temperature, ORC power plants are available from a variety of vendors, with plant size between 100 kWe and 50 MWe.

Selection of the ORC fluid is central to the success of the ORC. If a refrigerant will be used, the Ozone Depletion Potential and Global Warming Potential (GWP) will need to be considered during the selection. This has not been addressed during this feasibility report but should be considered in the next phase of engineering.

5.2 Heat Transfer Mechanism

Due to the sensitivity of the materials and small tolerances used in Heat Exchangers in an ORC package, the medium being passed through the equipment must not contain any impurities, solids or contaminants that may be picked up from fluid that has been in contact with the reservoir or well structure.

As the name suggests, the closed loop system will comprise well fluids within the downhole heat exchanger and therefore will not become contaminated with any debris, which means that it can be passed from the well directly to the ORC Evaporator and Pre-Heater. This is demonstrated in the Case 2 PFD.

Alternatively, the open loop case necessitates fluid being in direct contact with the well structure as well as bedrock and therefore it cannot be passed through the sensitive equipment of the ORC package in case of blockage. To work around this, an 'intermediate heat transfer loop' is employed to transfer the energy from the well fluid to the intermediate and subsequently from the intermediate fluid to the ORC fluid. This is demonstrated in both the Case 1 and Case 3 PFD.

5.3 Heat Sink

A seawater lift pump system is available on the Magnus Platform. The biggest user of seawater is the sea water injection system (c. 150,000 bwpd). Currently this water is pre-heated before de-aeration, so circulating this water through the ORC and then to de-aeration equipment would be optimal. For this reason, it is considered that seawater is available on the Magnus platform for cooling purposes in the potential ORC unit. Cooling in the ORC system via air coolers has not been considered due to the space constraints on the platform. It is noted that onshore ORC systems typically use large banks of air coolers as space is available.

The original Magnus platform design included five seawater lift pumps as detailed below:

- G-4403 is for essential supplies.
- G-4001 A-D are for non-essential supplies, the platform currently operates with 2 out of 3 of the seawater lift pumps running.
- G-4001C not in service and has been permanent removed.

For the purposes of the study, a 10°C annual average seawater temperature has been considered.

Any impact of reducing the water injection temperature on the reservoir has not been considered at this stage in this initial study. This should be further analysed in the next stage of engineering.

5.4 Heat Source Cases

Three approaches were identified to recover the heat available from the production wells:

1. Heat recovery from the produced water
2. Heat recovery from repurposing depleted wells using CeraPhiWell™ technology – a closed loop circulation system
3. Heat recovery from repurposing depleted wells through an open loop cross reservoir arrangement

The three approaches allowed the analysis of various ways to recover heat and combine with ORC technology to generate power, leading to various emission reduction opportunities on the Magnus platform depending on the stage of the lifecycle of the asset. The summary of the cases and their applications can be found in Table 15 and Table 17 respectively.

5.4.1 Case 1 – Power from Produced Water

5.4.1.1 Process Flow Diagram

For Case 1, the proposed strategy is to feed the produced water after it has been separated from the production stream to the Heat Transfer Exchanger (100-E-001) which will act as the intermediate Heat Exchanger between the produced water and the ORC unit. After the heat from the produced water stream has been transferred to the heat transfer medium (recycling between 100-E-001, 100-E-002 and 100-E-003), it will be fed to the Evaporator (100-E-002) and the Pre-Heater (100-E-003) to vaporise the ORC fluid. This energy transferred to the ORC will be used to generate power as described in Section 5.2.

After passing through the Heat Transfer Exchanger (100-E-001), the produced water will continue to the Magnus platform's water injection system to circulate through the well.

5.4.1.2 Potential Layout

Figure 11 shows the layout of a potential ORC package as a containerised solution. The Equipment List in 5.4.1.3 shows the dimensions of the ORC equipment inclusive of the service areas hence why the dimensions seem quite large. The stacking of the containers will allow for a smaller footprint on the platform and allow for a more efficient storage solution however this may make maintenance of the equipment more of a challenge. For Case 1, 6 of the containers shown in Figure 11 are required; this can either be done unstacked in a 3x2 (LxW) arrangement, or the containers can be stacked in a 3x2 (WxH) arrangement as shown in Table 9.

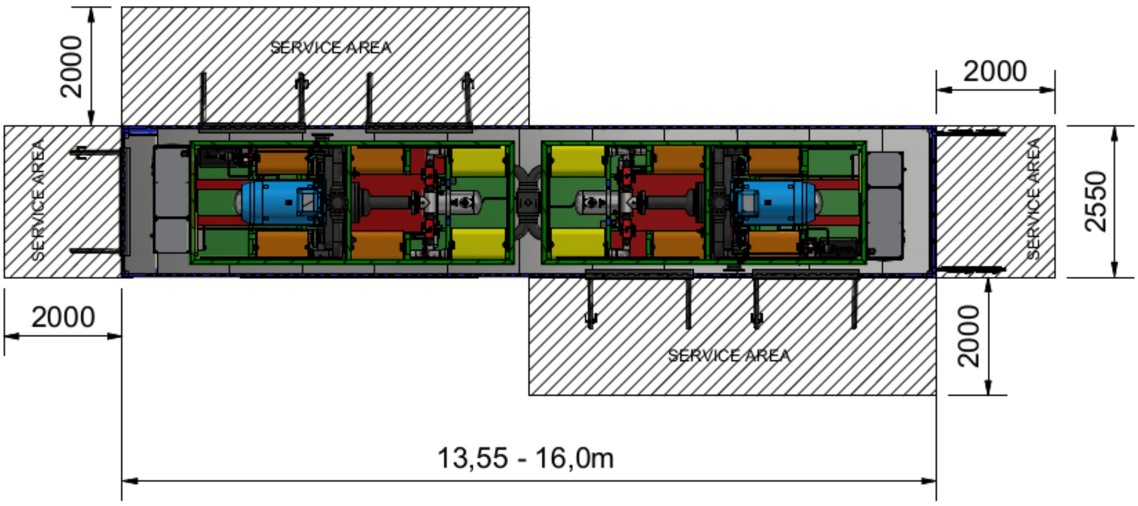


Figure 11 Layout of ORC Package from Vendor 2

The weight of the ORC package has not been considered at this stage. The next phase of engineering should assess whether the Magnus Platform can accommodate the weight of the package. It is noted that if other equipment is obsolete and removed from the platform then additional weight may become available.

5.4.1.3 Equipment List

Table 9 Case 1 - Equipment list for power from produced water (heat recovery)

TAG No	Equipment Name	Capacity	Unit	Dimensions								
				Vendor 1			Vendor 2 (Note 3)			Vendor 2 (Note 3)		
							Unstacked			Stacked		
				Length (mm)	Width (mm)	Height (mm)	Length (mm)	Width (mm)	Height (mm)	Length (mm)	Width (mm)	Height (mm)
(Note 1)	HP & LP Separation	1,093	m3/hr	(Note 2)			(Note 2)			(Note 2)		
100-E-001	Heat Transfer Exchanger	1,093	m3/hr	3,000	500	500						
100-E-002	Evaporator	VTC		20,000	2,300	2,300	35,100 (Note 4)	19,650 (Note 4)	2,600 (Note 4)	17,500 (Note 4, 5)	19,650 (Note 4, 5)	5,200 (Note 4, 5)
100-E-003	Pre-Heater	VTC		20,000	2,300	2,300						
100-C-001	Expander	VTC		3,500	2,200	2,700						
100-G-001	Generator	VTC		7,000	4,200	4,200						
100-E-004	Condenser	VTC		20,000	3,500	3,500						
100-P-001	Condensate Pump	VTC		VTC	VTC	VTC						

Notes:

1. Multiple separators currently in operation on Magnus platform. Produced water from all operating separators to be routed to ORC Package
2. Separator already present on Magnus platform
3. Dimensions stated inclusive of service areas shown in Figure 11
4. Two 200 kWe units will be placed inside a container. This sizing is based on a 3x2 (LxW) container arrangement
5. Two 200 kWe units will be placed inside stacked containers - two containers in height and three containers across - total footprint equivalent to three container

5.4.1.4 Parasitic Loads

Parasitic loads (or parasitic losses) are any power loads or devices powered by the generator, not contributing to net electric yield. For example, these would be the circulation pumps within the ORC loop or the water circulation pumps.

Table 10 outlines the results from the simulation that Petrofac ran to calculate heat flow from the produced water as well as the conversion to power from a single ORC unit. Referring to Table 10, vendor feedback suggested that there is a potential to generate 2.2 MWe of power from 13 ORC units. Hence, the total flowrate of produced water was split into 13 as shown above, to understand the power generation potential.

Table 10 Energy recovery potential from Produced Water

Case 1		
Heat Available		
Produced Water (PW) Flowrate	12,692	bpd
	83,911	kg/hr
Mass Heat Capacity	4.39	kJ/kg°C
PW ΔT	20	°C
Heat available to ORC	2,046.49	kW
Equipment Name	**Equipment TAG**	**Value (kW)**
Generator	100-G-001	249.1
Condensate Pump	100-P-001	27
	Net Power Generation	222.1
System Efficiency	**10.85%**	

5.4.2 Case 2 – Power from Repurposed Wells (Closed Loop)

5.4.2.1 Process Flow Diagram

Case 2 will involve the repurposing of depleted wells using CeraPhiWell™ technology in a closed loop system. The selected well fluid will circulate through a downhole heat exchanger to absorb the geothermal energy from the bottom of the well and return to the surface to pass through the Well Return Manifold (200-M-001). Following this, the well circulation fluid will be fed through the Evaporator (200-E-001) and the Pre-Heater (200-E-002) to transfer heat energy to the ORC fluid.

Note that in this case there is no need for a Heat Transfer Exchanger between the well fluid and the ORC fluid as this is a closed loop. The well fluid is never in any direct contact with the well structure does not bring any well material to the surface, which means that it can be passed through the ORC equipment without causing any damage. This energy transferred to the ORC will be used to generate power as described in Section 5.2. Case 2 will necessitate for 6 x 200 kW ORC units to be deployed.

After passing through the Evaporator (200-E-001) and the Pre-Heater (200-E-002), the well circulation fluid will be injected back into the well to continue the process of heat recovery. The Well Supply Buffer Tank (200-V-001) and the series of pumps will allow for a continuous supply of injection fluid to maintain adequate circulation and subsequent power generation.

5.4.2.2 Potential Layout

Figure 11 shows the layout of a potential ORC package as a containerised solution. The Equipment List in Table 11 shows the dimensions of the ORC equipment inclusive of the service areas hence why the dimensions seem quite large. Stacking of the containers has not been considered since only three containers will be required.

The weight of the ORC package has not been considered at this stage. The next phase of engineering should assess whether the Magnus Platform can accommodate the weight of the package. It is noted that if other equipment is obsolete and removed from the platform then additional weight may become available.

5.4.2.3 Equipment List

Table 11 Case 2 - Equipment list outlining the case for repurposed wells

TAG No	Equipment Name	Capacity	Unit	Dimensions			Dimensions		
				Vendor 1			Vendor 2 (Note 2)		
				Length (mm)	Width (mm)	Height (mm)	Length (mm)	Width (mm)	Height (mm)
200-M-001	Return Manifold	504	m3/hr	12,800	3,600	3,600	12,800	3,600	3,600
200-M-002	Supply Manifold	504	m3/hr	12,800	3,600	3,600	12,800	3,600	3,600
200-V-001	Well Supply Buffer Tank	504	m3/hr	12,800	3,600	3,600	12,800	3,600	3,600
200-P-001	Booster Pump	504	m3/hr	4,600	2,600	2,500	4,600	2,600	2,500
200-P-002	Well Fluid Circulation Pump	504	m3/hr	4,600	2,600	2,500	4,600	2,600	2,500
200-E-002	Evaporator	504	m3/hr	10,000	1,100	1,100	17,500 (Note 3)	19,650 (Note 3)	2,600 (Note 3)
200-E-003	Pre-Heater	504	m3/hr	10,000	1,100	1,100			
200-C-001	Expander	VTC		1,500	1,100	1,400			
200-G-001	Generator	VTC		3,500	2,100	2,100			
200-E-004	Condenser	VTC		10,000	1,750	1,750			
200-P-003	Condensate Pump	VTC		VTC	VTC	VTC			
200-V-002	ORC Buffer Tank	VTC		VTC	VTC	VTC	VTC	VTC	VTC

Notes:

1. Multiple separators currently in operation on Magnus platform. Produced water from all operating separators to be routed to ORC Package
2. Dimensions stated inclusive of service areas

5.4.2.4 Parasitic Loads

Table 12 outlines the results from the simulation that Petrofac ran to calculate heat flow from the well circulation water as well as the conversion to power from a single ORC unit. Referring to Table 12, vendor feedback suggested that there is a potential to generate 1.0 MWe of power from 5 ORC units. Hence, the total flowrate of well circulation water was split into 5 as shown above, to understand the power generation potential.

Table 12 Energy recovery potential from Closed Loop repurposed wells

Case 2		
Heat Available		
Well Circulation Water (PW) Flowrate	15,216	bpd
	100,598	kg/hr
Mass Heat Capacity	4.40	kJ/kg°C
PW Temp In	100.00	°C
PW Temp Out	80.00	°C
Heat to ORC	2,459.06	kW
Equipment Name	**Equipment TAG**	**Value (kW)**
Generator	200-G-001	488.00
Booster Pump	200-P-001	86.90
Well Fluid Circulation Pump	200-P-002	110.00
Condensate Pump	200-P-003	32.37
	Net Power Generation	258.73
System Efficiency	**10.52%**	

5.4.3 Case 3 – Power from Repurposed Wells, Reservoir Crossflow (Open Loop)

5.4.3.1 Process Flow Diagram

Case 3 involves the repurposing of the depleted production wells into Cross Flow Heat Recovery wells where produced water enters a typical injection well, travels to a source well and is extracted to the surface. It is then passed through a Well Return Separator (300-V-001) to remove out any salt, suspended solids, gas and oil that might have become entrained as this fluid will have directly contacted the well structure. After separation the heat absorbed by this fluid will be transferred to the ORC fluid via a Heat Transfer Exchanger (300-E-001) like in Case 1, due to contamination from the well, and this energy will be used to generate power as described in Section 5.2.

After passing through the Heat Transfer Exchanger (100-E-001), the produced water will proceed for reinjection through the Injection Buffer Tank (300-V-002) and a series of pumps.

5.4.3.2 Potential Layout

Figure 11 shows the layout of a potential ORC package as a containerised solution. The Equipment List (Table 13) shows the dimensions of the ORC equipment inclusive of the service areas hence why the dimensions seem quite large. The stacking of the containers will allow for a smaller footprint on the platform and allow for a more efficient storage solution however this may make maintenance of the equipment more of a challenge.

For Case 3, 4 of the containers shown in Figure 11 are required; this can either be done unstacked in a 4x1 (LxW) arrangement, or the containers can be stacked in a 2x2 (WxH) arrangement as shown in Table 13.

The weight of the ORC package has not been considered at this stage. The next phase of engineering should assess whether the Magnus Platform can accommodate the weight of the package. It is noted that if other equipment is obsolete and removed from the platform then additional weight may become available.

5.4.3.3 Equipment List

Table 13 Case 3 - Equipment list outlining case for repurposed wells with reservoir cross flow

TAG No	Equipment Name	Capacity	Unit	Temperature (°C)	Dimensions								
					Vendor 1			Vendor 2 (Note 3)					
								Unstacked			Stacked (Note 3)		
					Length (mm)	Width (mm)	Height (mm)	Length (mm)	Width (mm)	Height (mm)	Length (mm)	Width (mm)	Height (mm)
300-M-001	Return Manifold	644.06	m3/hr	112.3	14,000	4,000	4,000	14,000	4,000	4,000	14,000	4,000	4,000
300-V-001	Well Return Separator	644.06	m3/hr	112.3	13,868	3,962	3,962	13,868	3,962	3,962	13,868	3,962	3,962
300-E-001	Heat Transfer Exchanger	644.06	m3/hr	112.3	2,000	500	500	2,500	500	500	2,500	500	500
300-M-002	Supply Manifold	553.76	m3/hr	112.3	14,000	4,000	4,000	14,000	4,000	4,000	14,000	4,000	4,000
300-V-002	Injection Buffer Tank	553.76	m3/hr	112.3	13,868	3,962	3,962	13,868	3,962	3,962	13,868	3,962	3,962
300-P-001	Booster Pump	553.76	m3/hr	112.3	4,600	2,600	2,500	4,600	2,600	2,500	4,600	2,600	2,500
300-P-002	Well Fluid Circulation Pump	553.76	m3/hr	112.3	4,600	2,600	2,500	4,600	2,600	2,500	4,600	2,600	2,500
300-E-002	Evaporator	553.76	m3/hr	112.3	10,000	1,100	1,100	35,000	13,100	2,600	17,500	13,100	5,200
300-E-003	Pre-Heater	553.76	m3/hr	112.3	10,000	1,100	1,100						
300-C-001	Expander	VTC		VTC	1,500	1,100	1,400						
300-G-001	Generator	VTC		VTC	3,500	2,100	2,100						
300-E-004	Condenser	VTC		VTC	10,000	1,750	1,750						
300-P-003	Condensate Pump	VTC		VTC	VTC	VTC	VTC						
300-V-002	ORC Buffer Tank	VTC		VTC	VTC	VTC	VTC	VTC	VTC	VTC	VTC	VTC	VTC

Notes:

1. Reduction in capacity from 644.06 m^3/hr to 553.76 m^3/hr is a result of removal of oil from recovered well fluid - based on an 85.98 % average water cut across the MSM reservoir
2. Two 200 kWe units will be placed inside one container. Seven ORC units required hence 4 containers will be needed
3. Dimensions stated inclusive of service areas
4. Stacked container arrangement - 2 containers in height and 2 containers across - total footprint would be of 2 containers

5.4.3.4 Parasitic Loads

Table 14 outlines the results from the simulation that Petrofac ran to calculate heat flow from the produced water as well as the conversion to power from a single ORC unit. Referring to Table 14, vendor feedback suggested that there is a potential to generate 1.3 MWe of power from 7 ORC units. Hence, the total flowrate of produced water was split into 7 as shown above, to understand the power generation potential.

Table 14 Heat Recovery from Cross Reservoir Repurposed Wells

Case 3		
Heat Available		
Produced Water (PW) Flowrate	13,888	bpd
	91,815.52	kg/hr
Mass Heat Capacity	4.40	kJ/kg°C
PW Temp In	100.00	°C
PW Temp Out	80.00	°C
Heat Available	2,244.38	kW
Equipment Name	**Equipment TAG**	**Value (kW)**
Generator	300-G-001	467.6
Booster Pump	300-P-001	70.9
Well Fluid Circulation Pump	300-P-002	117.3
Condensate Pump	300-P-003	29.5
	Net Power Generation	250
System Efficiency	**11.14%**	

5.5 Summary of Cases

A number of ORC vendors were consulted to obtain heat recovery potentials that could be used in each case, and both took into consideration a 20°C temperature drop of the produced water side from 100°C to 80°C as energy is transferred to the ORC fluid. As a result of this, the maximum power generation potential using the produced water came out to be 4.5 MWe from a bespoke solution with individual equipment items (not modularised or containerised) while an alternative solution provided a potential of 2.4 MWe from a series of containers.

It should be noted that there is a difference between the Heat Available and the Power Generation Potential. Like any power generation system, an ORC system is not 100% and all thermal potential is not converted to usable electricity. ORC systems are approximately 10% efficient for low grade heat in the 100 to 120 °C range.

There are also some parasitic loads within the system; notably the power required to circulate well fluids through a closed loop system and the power required to pump the organic working fluid around the ORC system. The parasitic loads have been deducted from overall Power Generation Potential values presented below and thus the values are net.

The parasitic loads for each case have been discussed in previous sections. It should be noted that Petrofac ran independent simulations to establish heat flows and conversion to power hence the figures for power generation in the above sections may be different to the potentials from vendors outlined below.

Table 15 summarises the three heat source cases that have been discussed in section 5.4 of the report and the applications of these options in are outlined in Table 17.

Table 15 Summary of heat recovery scenarios discussed in the study

	Case 1	Case 2	Case 3
Description	Produced Water	Closed Loop	Open Loop
Fluid	Produced Water from reservoir (contains salt, suspended solids, entrained gas and oil)	Clean water (no impurities)	Produced Water from reservoir (contains salt, suspended solids, entrained gas and oil)
Flow Rate	165,000 bwpd	67,930 bwpd (25 wells at 5 l/s circulation)	97,216 bwpd
Temperature	100°C	120°C	115°C
Heat Available	26.02 MWth (Assumes 20°C drop across inlet exchanger)	11 MWth (Assumes 20°C drop across inlet exchanger)	13.55 MWth (Assumes 20°C drop across inlet exchanger)
Power Generation Potential	Option 1 is a containerised solution to provide 2.2 MWe Option 2 is a bespoke solution to provide up to 4.5 MWe	Option 1 is a containerised solution to provide 1.0 MWe Option 2 is a bespoke solution to provide up to 2.1 MWe	Option 1 is a containerised solution to provide 1.3 MWe Option 2 is a bespoke solution to provide up to 2.7 MWe

5.5.1 Cost of Equipment

Preliminary cost estimates have been prepared for the different options identified based on discussions and interaction with ORC vendors. The accuracy of the cost estimates should be considered as order of magnitude at this stage.

Table 16 Cost of Equipment

Case		Power out MW	Equipment Price	Approximate TIC
1 Produced Water	Option 1	2.2	£ 5,800,000	£29,000,000
	Option 2	4.5	£13,000,000	£65,000,000
2 Closed Loop	Option 1	1	£ 3,400,000	£17,000,000
	Option 2	2.1	£ 5,600,000	£28,000,000
3 Open Loop	Option 1	1.3	£ 3,900,000	£19,500,000
	Option 2	2.7	£ 7,100,000	£35,500,000

Detailed operating costs have not been established for the revised system. Should screening level economics be required then an annual OPEX value equal to 2.5% of the total capital cost is recommended.

6 WP 7: Review of options

The three evaluated potential ways of using geothermal energy to decarbonize the Magnus field include heat recovery from hot produced water, repurposing platform wells using a closed-loop geothermal heat exchanger and using the reservoir with injector and producer wells (a so-called open-loop system). An Organic Rankine Cycle (ORC) generator was selected as the power generation technology for all three geothermal options.

The produced water stream has the highest potential of the three options to decarbonize the current oil and gas production of the Magnus platform. The produced water is 165,000 bwpd at 100 °C, which with a 20 °C drop through the ORC system equates to a thermal output of 26.02 MWth.

Due to the relatively low bottom hole temperatures, and well tubulars which constrain the fluid flow rates using the 25 platform wells to be repurposed with a CeraPhiWell™ closed-loop co-axial heat exchanger would give relatively modest heat recovery of 0.44 MWth per well or a total of 11 MWth.

A new drilled and optimised design of CeraPhiWell™ would be able to generate much higher heat recovery rates of 1.6 MWth per well. Unfortunately, due to all existing well slots being fully utilised there is no possibility at the moment to drill and install a new CeraPhiWell™. However, there could be the potential to sidetrack from existing wells at the from 9-5/8" or remove part of the 9-5/8" casing and then sidetrack from the 13-3/8" to allow for a larger higher output CeraPhiWell™ installation.

The review of a cross reservoir geothermal system identified there is communication between a number of injectors and producers across the field that would be suitable for an open loop geothermal system, which would be a potential geothermal heat source only after Cessation of Production. The potential installed capacity of this system is estimated to be up to 2.7 MWe, generating 23,652 MWh per annum and saving 15,540 tons CO_2eq per annum.

This section will consider the heat source and ORC opportunities described above in respect to the different operational phases that the Magnus platform will go through in its expected lifetime.

Table 17 below presents a summary of the potential heat source applications across these different phases, with further discussion in the subsequent sub-sections.

Table 17 Heat Source Applications

Phase	Heat Source Available	Power Required / Target	Potential
Production Operations Phase (current)	▪ Produced water stream of 165,000 bwpd at 100°C, a 20°C drop through ORC kit equals 26.02 MWth ▪ Possible reuse of wells for geothermal purposes – but likely all existing wells required for production	Overall platform power load is circa 30 MW for operations phase	▪ Option 1 is a containerised solution to provide 2.2 MW ▪ Option 2 is a bespoke solution to provide up to 4.5 MW
Decommissioning / P&A Activities	▪ Transfer of well stock from production to power generation ▪ 0.44 MWth per well available, up to 11 MWth from 25 wells	The power requirements to support P&A activities is approx. 5 MW (from diesel)	▪ Option 1 is a containerised solution to provide 1.0 MW ▪ Option 2 is a bespoke solution to provide up to 2.1 MW
Post Decommissioning Phase – Magnus as a CCS Hub	▪ Repurposing of wells for geothermal power generation ▪ 0.44 MWth per well available, up to 11 MWth from 25 wells	The exact power requirements need to be confirmed, circa 3 to 4 MW is considered depending on CO2 pumping	TBC confirmed, further definition of the CCS hub requirements and redundant equipment is required.

6.1 Current Production Phase

The Magnus platform has a current power demand of 30 to 40 MWe and most of this is required for water injection and gas compression. The platform is using natural gas to generate electricity.

All current 25 wells are being used for oil production so are unavailable for repurposing with a CeraPhiWell™ system, hence the potential addition heat source from these wells would not be available during this current operational phase.

Using heat from the produced water stream would enable between 2.2 or 4.5MW of carbon free power to be generated, depending on whether a containerised solution was used (which could deliver 2.2 MW) or a bespoke system (which could deliver up to 4.5 MW). This would be approximately 10% of the current platform power demand.

Spaces on the topsides may be available for installing a bespoke ORC solution but this needs to be discussed with EnQuest and a more detailed engineering evaluation undertaken. Additional space could also be created with a deck extension to accommodate the ORC units and this again would need further review and evaluation.

6.2 Decommissioning / P&A Phase

There would be many logistics challenges to overcome to install a CeraPhiWell™ and ORC system on Magnus during a decommissioning programme, where installing new equipment at the same time as removing old unrequired equipment would be required.

If this were to be considered then wells being decommissioned could be converted to a CeraPhiWell™ completion as the decommissioning program advances, and each well could provide 0.44 MW of thermal energy for conversion into electrical power by an ORC system.

Adding ORC capacity progressively by installing equipment in spaces left by removal of not required topsides systems would be made easier if a containerised system was deployed. Also as identified above, the space currently utilised by the EOR compressor may be a potential solution.

In order to more fully consider this option, the power demand during decommissioning would need to be evaluated and confirmed. The heat source availability would also need to be understood, which could be a combination of produced water and repurposed wells. Finally, the decommissioning programme would need to be clearly set out in order to prepare a preliminary programme of work and evaluate to practicality of this solution during this phase of platform operations.

6.3 Post Decommissioning Phase

There are plans for the Magnus platform to be re-developed for Carbon Capture & Storage (CCS). At present, EnQuest has four CCS licenses for the NNS.

At Sullum Voe, the imported CO_2 would be temporarily stored in liquid form in tanks, and then pumped down the pipeline to Magnus platform. In the current evaluations, Magnus is considered as a centralized operational hub in which water treatment facilities can be installed and provide service to surrounding fields with similar CCS operations during and after transitioning to end of life of oil and gas production.

In the current plans for CO_2 injection, there would be limited power demand for liquefied CO2 injection, being one order of magnitude less than the current demand, i.e., circa 3-4 MWe is expected. During CO_2 injection, the Magnus platform is likely to be normally unattended and would host CO_2 pumping, instrumentation, control, and water treatment facilities to support CO_2 injection. Repurposed wells and ORC systems could provide power for the CO_2 injection at Magnus.

To better understand the opportunity for decarbonising power generation during this operational phase further analysis would be needed including:

- Power demand for Magnus as a CCS hub needs to be understood.
- Produced water volume may reduce over time so reduction in this heat source may need to be replaced using repurposed wells.

Consideration could also be given to investigate and evaluate the potential of a geothermal system that will use the injected CO_2 as the heat carrier fluid for heat extraction from the existing reservoir for power generation. This could allow both CCS and geothermal power generation to run simultaneously and it is illustrated in the diagrams below (Figure 12 and Figure 13).

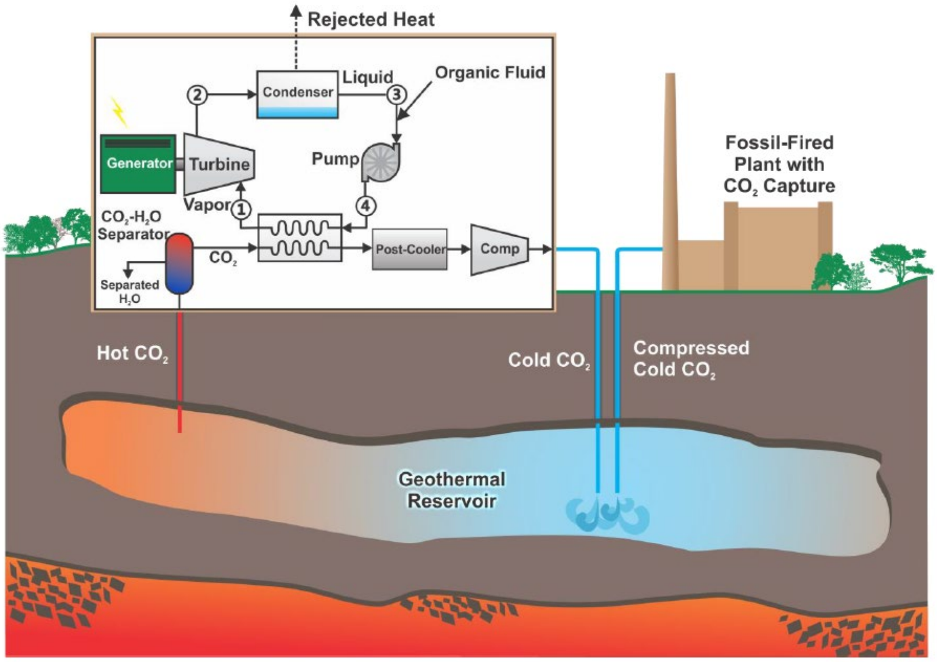


Figure 12 Sketch of ORC power generation using hot produced CO_2 from a geothermal reservoir[1]

[1] Wang et al (2019), Working fluid selection for Organic Rankine Cycle power generation using hot produced supercritical CO2 from a geothermal reservoir. Available at: https://www.sciencedirect.com/science/article/abs/pii/S1359431118354589

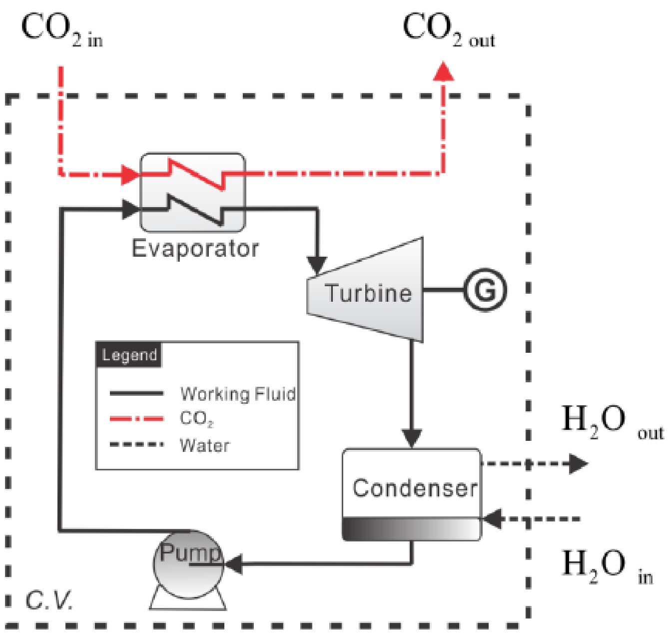


Figure 13 Control volume for ORC exergy and thermal efficiency calculation

6.4 Potential for other UKCS platforms

The Magnus platform has a high volume of produced water with temperatures of around 100 °C available for renewable geothermal power production. This is typical for many platforms in the UKCS and while there are other platforms that have higher rates of produced water these are generally at lower temperatures. Hence the power that could be achieved from produced water in other platforms would likely be similar to that which could be found on Magnus.

Fields with High-Pressure High-Temperature (HPHT) reservoirs that could have wellhead temperature of over 150°C, such as Elgin Franklin which has temperatures above 170°C could allow greater heat recovery from wells repurposed with a CeraPhiWell™ system, even if the well construction and tubular sizing were to be similar to Magnus.

Opportunities with other UKCS installations may arise where wells have either been, or are shortly going to be, suspended prior to full decommissioning and abandonment. There are no such candidates currently on the Magnus platform however it is believed there are platforms in the North Sea where such wells would be available for repurposing. However as found in this study where the construction of well tubulars have been designed for oil & gas production this is not ideal for geothermal use due to the tubular diameters being smaller and hence restricting the flowrate that can be used in an economic way.

On Magnus there are no free well slots that could be used to drill and install a new CeraPhiWell™ but if there were other platforms that did have this availability this could provide an ideal opportunity to install a new geothermal well and ORC power generation system which could provide significantly higher energy output than would be available from a typical repurposed well based system.

Platforms installed in the UKCS were generally designed and built to minimise the amount of unused topsides space, of which Magnus is a typical example. However as with the potential space that could be created by removal of the EOR compressor on Magnus other platforms in the North Sea could have unused equipment packages that could be removed and give the opportunity to install an ORC system, either as a containerised package or installed in discrete components as a bespoke system.

6.5 Carbon emissions

The potential is clear for reducing the amount of carbon dioxide currently released through burning fossil fuels to provide power for offshore platforms by using readily available heat sources such as produced water streams and developing deep geothermal systems. The exact quantity for such a system on Magnus would depend on at what point in the operational timeline and also what specific system was actually installed. The key point being the more geothermal heat energy that is harvested and fed into an ORC generator, the more CO_2 emissions can be saved.

For every MWh per year that could be generated using clean geothermal power the amount of darbon dioxide not released to the atmosphere is **0.653 tons per year**.

For a system using the produced water as a source this has a generating capacity of up to 4.5 MWe this provides 39,420 MWh per year thus saving **25,751 tons of CO_2** equivalent annually.

If all 25 wells were repurposed using the CeraPhiWell™ system this could generate up to 2.1 MWe generating 18,396 MWh per year saving **12,017 tons of CO_2** annually.

Figures for new drill CeraPhiWell™ and cross reservoir system can similarly be calculated once the specific case has been developed.

7 Conclusions and Recommendations

7.1 Conclusions

Magnus Asset

- There is potential to install ORC systems to use heat from produced water and generate clean electrical power during current production phase. This potential is approximately 10 % of the platform power demand and would save 25,800 tons of CO_2 equivalent per year.
- The Magnus platform has a congested layout however EnQuest have advised that the EOR compressor is not required and if removed an ORC system could be installed there. This is a space of approximately 10 m x 23.5 m.
- There appears to be very limited opportunity to repurpose existing wells during the current production phase.
- Additionally repurposing wells and installing ORC systems is unlikely to be practicable during the decommissioning phase
- The post decommissioning phase offers the greatest potential for using geothermal heat to generate electrical power. During this phase Magnus may be employed as a CCUS hub and the platform energy demand would be reduced by an order of magnitude from the current demand, going down to approximately 4 MW. An ORC system could be installed to provide this electricity demand from a combination of repurposed wells and produced water stream, providing a clean geothermal power source.
- An additional benefit post decommissioning is the cross-reservoir option whereby energy could be produced from the Magnus reservoir by using water or CO_2 as working fluid with the deployment of an appropriate scheme of injectors / producers. The power produced at this phase could provide additional power to the CCS injection operations in Magnus and surrounding platforms, water treatment facilities and oil & gas production in surrounding platforms. Alternatively, it could potentially be exported to the UK National Grid if a nearby grid connection were available from an offshore windfarm for instance.

Wider UKCS

Despite the considered clean energy opportunity at the Magnus platform, other installations in the UKCS may have more favourable characteristics such as:

- Hotter produced water of higher bottom hole temperatures as may be found on HP/HT reservoirs.
- Wells that have larger casing sizes at the bottom allowing better flowrates and improved heat recovery.
- Platforms that have available suspended wells for repurposing or free well slots that could be used for new drill CeraPhiWells.
- Platforms that have less congested decks or easily accessible open areas to install ORC systems.

7.2 Recommendations

It is recommended that this study is progressed to the next stage with particular focus on the post decommissioning phase and the potential for Magnus to become a CCS hub. It is recommended that the level of existing equipment on the platform be reviewed with a view to establishing a full range of spaces available for ORC equipment that could provide electricity for life support and power demanded by the CCS activities.

The Magnus platform, as the next CCS hub can be used as case study for optimizing other existing offshore platforms for CCS using geothermal energy. The next stage of this study should focus on optimising the Magnus platform deck space, existing equipment, existing wells, and power generation systems for power production for life support and power required post CoP during the CCS stage.

The co-produced water is expected to be rejected into the sea and not re-injected back into the formation. As a result, the co-produced water production from the Magnus field will decline and eventually be depleted while the CO_2 is being injected into the formation. This will reduce the potential of using the co-produced water post CoP for power production. The closed-loop geothermal system does not depend on the co-produced fluids and can be installed to partially power the CCS operations. The thermal energy from the closed-loop wells can also be used to treat the additional water flowing from other platforms. The CCS operations will not require all of existing injector and producer wells. These could be repurposed for additional power generation capacity from closed loop systems. The study should also explore the potential of using the injected CO_2 as a heat carrier fluid for power generation in addition to the power generated from the closed-loop wells as part of a hybrid solution.

Further work on enhancing the heat outputs from the wells would also be recommended and could include:

- Look at sidetracking of existing wells. This could either be pulling the existing 9-5/8" casing and then sidetracking from the 13-3/8" or alternatively sidetrack from 9-5/8".
- Consider increasing the number of well slots on the platform to allow a new drill CeraPhiWell™ installation thereby generating significantly increased heat and power outputs.

Consider initiating a review of existing UKCS platforms to:

- Identify potential candidates for repurposed or new drill wells mapping the key characteristics for effective geothermal energy production.
- Find public sources of information and access to data from previous studies (i.e. mass flow rates from UK platforms from the previous DECC and temperature data collected in academic studies).
- From this work identify potential platforms for further study that would be guided by the work carried out on this Magnus study.

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