Department for
Business, Energy
& Industrial Strategy

Endurance Field Wells Cost Estimate

Key Knowledge Document

NS051-WE-EST-000-00001

This Key Knowledge Document (KKD) was generated as part of the pre-FEED project stage for NEP/NZT and completed in June 2021. This document release was put on hold to allow for the application process for the carbon dioxide licenses CS006 and CS007 by the North Sea Transition Authority to be completed and the licenses awarded in May 2022. The contents of the KKD does not fully reflect the subsequent work after drafting in June 2021.

May 2022

Acknowledgements

The information in this report has been prepared by bp on behalf of itself and its partners on the Northern Endurance Partnership project for review by the Department of Business, Energy and Industrial Strategy ("BEIS") only. While bp believes the information and opinions given in this report to be sound, all parties must rely upon their own skill and judgement when making use of it. By sharing this report with BEIS, neither bp nor its partners on the Northern Endurance Partnership project make any warranty or representation as to the accuracy, completeness, or usefulness of the information contained in the report, or that the same may not infringe any third party rights. Without prejudice to the generality of the foregoing sentences, neither bp nor its partners represent, warrant, undertake or guarantee that the outcome or results referred to in the report will be achieved by the Northern Endurance Partnership project. Neither bp nor its partners assume any liability for any loss or damages that may arise from the use of or any reliance placed on the information contained in this report.

Any enquiries regarding this publication should be sent to us at:
enquiries@beis.gov.uk

Contents

1.0 Foreword

The Net Zero Teesside (NZT) project in association with the Northern Endurance Partnership project (NEP) intend to facilitate decarbonisation of the Humber and Teesside industrial clusters during the mid-2020s. Both projects will look to take a Final Investment Decision (FID) in early 2023, with first CO2 capture and injection anticipated in 2026.

The projects address widely accepted strategic national priorities – most notably to secure green recovery and drive new jobs and economic growth. The Committee on Climate Change (CCC) identified both gas power with Carbon Capture, Utilisation and Storage (CCUS) and hydrogen production using natural gas with CCUS as critical to the UK's decarbonisation strategy. Gas power with CCUS has been independently estimated to reduce the overall UK power system cost to consumers by £19bn by 2050 (compared to alternative options such as energy storage).

1.1 Net Zero Teesside Onshore Generation & Capture

NZT Onshore Generation & Capture (G&C) is led by bp and leverages world class expertise from ENI, Equinor, and TotalEnergies. The project is anchored by a world first flexible gas power plant with CCUS which will compliment rather than compete with renewables. It aims to capture ~2 million tonnes of CO2 annually from 2026, decarbonising 750MW of flexible power and delivering on the Chancellor's pledge in the 2020 Budget to "support the construction of the UK's first CCUS power plant." The project consists of a newbuild Combined Cycle Gas Turbine (CCGT) and Capture Plant, with associated dehydration and compression for entry to the Transportation & Storage (T&S) system.

1.2 Northern Endurance Partnership Onshore/Offshore Transportation & Storage

The NEP brings together world-class organisations with the shared goal of decarbonising two of the UK's largest industrial clusters: the Humber (through the Zero Carbon Humber (ZCH) project), and Teesside (through the NZT project). NEP T&S includes the G&C partners plus Shell, along with National Grid, who provide valuable expertise on the gathering network as the current UK onshore pipeline transmission system operator.

The Onshore element of NEP will enable a reduction of Teesside's emissions by one third through partnership with industrial stakeholders, showcasing a broad range of decarbonisation technologies which underpin the UK's Clean Growth strategy and kickstarting a new market for CCUS. This includes a new gathering pipeline network across Teesside to collect CO2 from industrial stakeholders towards an industrial Booster Compression system, to condition and compress the CO2 to Offshore pipeline entry specification.

Offshore, the NEP project objective is to deliver technical and commercial solutions required to implement innovative First-of-a-Kind (FOAK) offshore low-carbon CCUS infrastructure in the UK, connecting the Humber and Teesside Industrial Clusters to the Endurance CO2 Store in the Southern North Sea (SNS). This includes CO2 pipelines connecting from Humber and Teesside compression/pumping systems to a common subsea manifold and well injection site at Endurance, allowing CO2 emissions from both clusters to be transported and stored. The NEP project meets the CCC's recommendation and HM Government's Ten Point Plan for at least two clusters storing up to 10 million tonnes per annum (Mtpa) of CO2 by 2030.

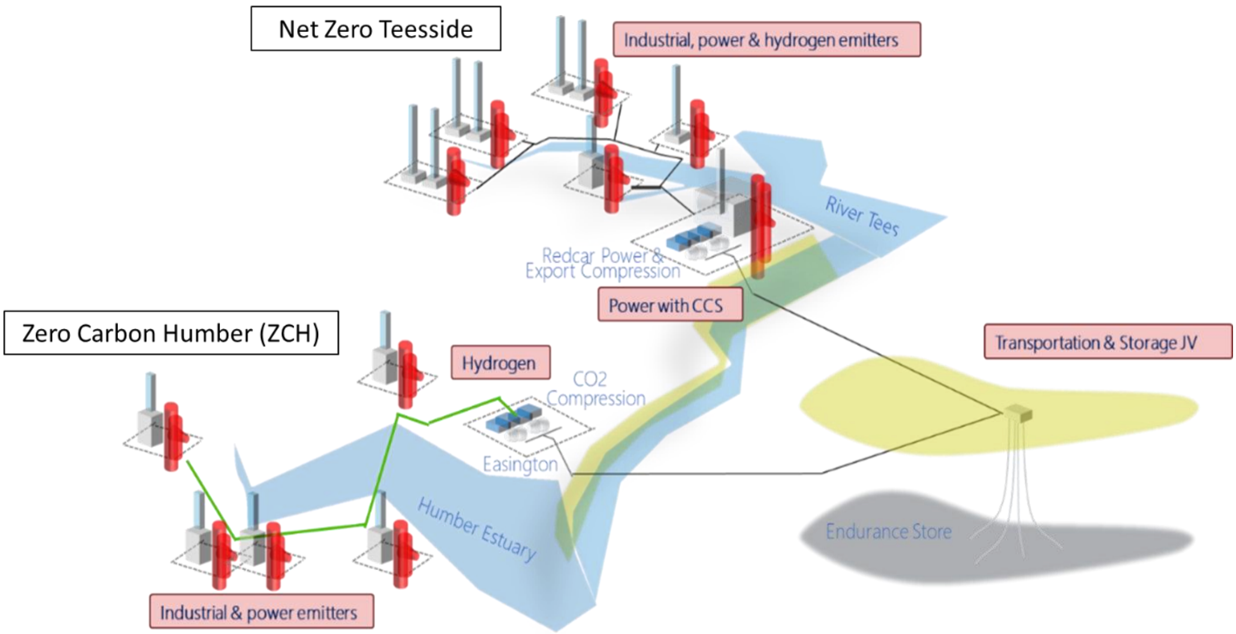


Figure 1: Overview of Net Zero Teesside and Zero Carbon Humber projects.

The project initially evaluated two offshore CO2 stores in the SNS: 'Endurance', a saline aquifer formation structural trap, and 'Hewett', a depleted gas field. The storage capacity requirement was for either store to accept 6+ Mtpa CO2 continuously for 25 years. The result of this assessment after maturation of both options, led to Endurance being selected as the primary store for the project. This recommendation is based on the following key conclusions:

- The storage capacity of Endurance is 3 to 4 times greater than that of Hewett
- The development base cost for Endurance is estimated to be 30 to 50% less than Hewett
- CO2 injection into a saline aquifer is a worldwide proven concept, whilst no benchmarking is currently available for injection in a depleted gas field in which Joule-Thompson cooling effect has to be managed via an expensive surface CO2 heating solution.

Following selection of Endurance as the primary store, screening of additional stores has been initiated to replace Hewett by other candidates. Development scenarios incorporating these additional stores will be assessed as an alternative to the sole Endurance development.

2.0 Introduction

Net Zero Teesside & Northern Endurance Partnership (NZT/NEP) is a Carbon Capture and Storage (CCUS) project in the Southern North Sea (SNS) formerly owned by the Oil and Gas Climate Change Initiative (OGCI) by now operated by BP on behalf of and itself and its partners, comprising ENI, Equinor, Shell and Total.

The offshore scope of the NZT/NEP Project combined with the offshore scope of the Zero Carbon Humber Project (which is another CCUS project) will both use the Endurance saline aquifer as the CO2 store. The combined offshore project is known as the Northern Endurance Partnership (NEP).

Six subsea wells will be drilled in the first phase of the project to inject CO2 into the Endurance field which is a saline aquifer. A jack-up rig will be used as the relatively shallow water depth (~60m) is unsuitable for a semi-submersible.

The six phase 1 wells comprise five CO2 injectors (four plus one spare) and an observation well on the crest of the to monitor plume migration via pressure measurements and production logging.   Optimisation as the project progresses may allow the observation well functionality to be incorporated into one of the four injection wells, or the observation well to be used for future CO2 injection – this work will be tied into the subsea layout and architecture work as well location is key.

In common with many Southern North Sea (SNS) wells targeting the Bunter Sandstone, the well design assumes three casing strings and a perforated liner across the reservoir section.

Drilling will start in 2024 with all wells drilled before first CO2 injection in 2026.

This document summarises the wells time and cost estimate which has been performed during the combined Concept Development and Optimise (CD&O) phase of the project including all relevant assumptions.

It should be noted that although BP is operator, the equity split between the partnership has not been agreed at this stage, and so BP net figures are not presented in this document and only gross costs are presented.

3.0 DRILLEX Summary

Well Details	
Region	North Sea
Field / project	Endurance / Northern Endurance Partnership
Rig name	TBC (jack-up)
Well name	TBC
Number of wells	Six (5 CO2 Injectors, 1observation well for Phase 1)
Well type	CO_2 Injectors
Water Depth	~60m
Well Depth	Range from 1270mMD to 1480mMD (not including sump)
No. casing strings	3
No. of sidetracks	0 (1 pilot hole for crestal/observation well)
Completion type	Cased and perforated
P50 Spud date	2024
BP Equity	TBC
Other well info	Subsea wells for CO2 injection. Assume all wells are vertical and drilled from standalone locations. Crestal well also includes a pilot hole, coring and additional WL all for data acquisition.

Total Well Cost & Time Estimate			
	Gross cost $MM	Duration, days	NPT %
Base	192	317	25
UAP	26	53	-
PT	218	370	36
AUAP	37	75	-
NTE	255	445	43

Details of FM being supported			
Type	☒ Define FM	☐ Execute FM	☐ Supplemental FM
Value	Removed		

Details of previously approved funding	
Value	Not Applicable
VOWD	Not Applicable

Table 1 Drillex Summary

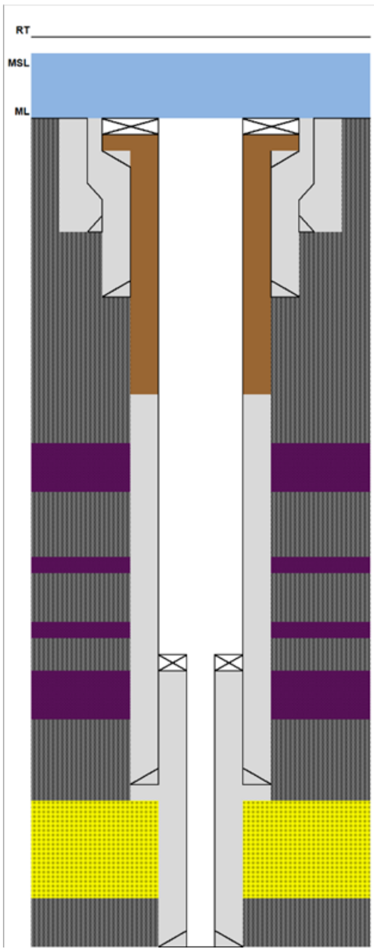
4.0 Scope of Estimate

4.1 Overview

This following scope is included in this estimate:

- Phase 1 wells
- Five subsea CO2 injectors drilled as part of a distributed subsea layout (stand-alone wells)
- One subsea observation well vertical well drilled on the crest of structure
- Observation well to include a pilot hole for data acquisition in the shallow sections
- Observation well to also include coring and additional wireline data acquisition
- It is assumed that the wells are drilled in a single campaign by a jack-up
- It is assumed that the wells will have vertical trees which are run from the rig

An example schematic of a 3-string NZT/NEP subsea CO2 injector is shown below:



	mMD BRT	mTVD BRT	mMD SS	mTVD SS	Inclination	Azimuth	Comment
RT	0	0	-25	-25	0	0	
MSL	25	25	0	0	0	0	
Seabed/Mud Line	85	85	60	60	0	0	
30" x 20" Conductor TOC	85	85	60	60	0	0	assume cemented back to ML
20" x 13-3/8" Casing TOC	85	85	60	60	0	0	assume cemented back to ML
Lias	101	101	76	77	0	0	
30" x 20" Conductor	157	157	132	132	0	0	assume 6 joints of conductor
20" x 13-3/8" Casing	445	445	420	420	0	0	assume 13-3/8" set max 30 deg Inc
Winterton (Top Triassic)	548	548	523	523	0	0	
9-5/8" Casing TOC	584	584	559	559	0	0	assume TOC 600m above shoe (leave lower completion in place for PA)
Halsborough	593	593	568	568	0	0	
Top Keuper Anhydrite	609	609	584	585	0	0	
Base KeuperAnhydrite	649	649	624	625	0	0	
Dudgeon	699	699	674	674	0	0	
Dowsing	804	804	779	780	0	0	
Top Muschelkalk Halite	855	855	830	830	0	0	
Base Muschelkalk Halite	917	917	892	893	0	0	
7" Liner TOC	1034	1034	1009	1009	0	0	assume cemented back to Liner Top
7" Liner (top)	1034	1034	1009	1009	0	0	assume 150m above 9-5/8" casing
Rot Halite 3	1058	1058	1033	1034	0	0	
Rot Halite 2	1071	1071	1046	1046	0	0	
Rot Halite 1	1092	1092	1067	1068	0	0	
Rot Clay	1177	1177	1152	1153	0	0	
9-5/8" Casing	1184	1184	1159	1159	0	0	assume 9-5/8" midway through rot clay
Bunter Sandstone	1191	1191	1166	1166	0	0	
Bunter Shale	1506	1506	1481	1481	0	0	
7" Liner	1639	1639	1614	1614	0	0	assume set at TD
TD	1639	1639	1614	1614	0	0	

Figure 2 Example NZT/NEP CO2 Injection Subsea Well Schematic

5.0 Time Estimate

The breakdown of well times is as per the Table 2 below:

Well	Time (days)			Comments
	Base	PT	NTE	
Overall Project	317	370	445	
CI1	58	68	87	Includes initial rig move
CI2	55	64	81	Includes rig move
CI3	52	61	77	Includes rig move
CI4	50	59	75	Includes rig move
CI5	49	57	73	Includes rig move
OE1	54	62	78	Includes rig move, pilot hole and additional data acquisition (logging and coring)

Table 2 NZT/NEP Wells Time Summary

The basis and assumptions behind these times are detailed in the sections 0 to 0.

5.1 Excluded Scope

This following scope is not included in this estimate:

- Exploration or Appraisal wells for additional stores
- CO_2 injector wells for future phases of the development
- Brine production wells may be required in future the NZT/NEP project to control reservoir pressure – these are not included
- Rig mobilisation. The estimate assumes that there will be a suitable rig working in the Southern North Sea. Note that a provision for bp rig verification is included (see Section 0)
- Subsea wellhead and tree costs. The estimate assumes that wellhead and tree costs are covered by GPO under GSS
- Well abandonment costs

5.2 Analogue and Offset Wells

An industry database was used to identify relevant offset well data.

5.2.1 Drilling Offsets

For drilling offsets, the filter criteria were selected in order to target development wells in neighbouring blocks in the Southern North Sea where a jack-up rig was used. Filters were also selected to ensure wells of similar depth were selected. This approach ensured that the offsets were drilled with the same rig type as planned for NZT/NEP and were drilled through a comparable measured depth interval of similar geology.

Drilling Offset Search Criteria:

Country:	"UK"
Well Type:	"Development"
Hole Type:	"New Well"
Block Number:	"41 or 42 or 43 or 44 or 45 or 47 or 48 or 49 or 52 or 53"
Rig Type:	"Jack-up"
Water Depth:	"less than 100m"
Drill Interval:	"less than 5000m"
TVD:	"less than 3000m"

The offset data was de-constructed to separate productive and non-productive times for use in the well time and cost model with data points considered outliers removed. Triangular distributions (min/most likely/max values) were then used in the wells time and cost model for productive time (m/day) and NPT (%).

5.2.2 Completion Offsets

For completions, the filter criteria were selected in order to target new subsea completions in in the North Sea. Filters were also selected to ensure wells of similar depth to those for this project were selected.

Applying further filters resulted in a small sample set of benchmarking data - e.g. if a jack-up rig was selected, this was found to reduce the number of wells by more than 60%. Filters for the tree-type were not applied as it is currently unknown what type of tree will be used for the NZT/NEP wells though a vertical tree is expected.

Completion Offset Search Criteria:

Region:	"Europe"
Sub-Region:	"Central North Sea, Northern North Sea, Southern North Sea"
Surface Location:	"Subsea"
Data Type:	“New Completion”
Water Depth :	"less than 100m"
MTD:	"deeper than 2000m and less than 3000m"

The offset data was de-constructed to separate productive and non-productive times with data points considered as outliers removed.

5.3 Productive Time

A simplistic approach was taken to the well times as there is currently limited definition around the well design.

5.3.1 Drilling

Information from de-constructed offset data described above was used to generate a triangular distribution for productive drilling rates expressed in m per productive dry hole day:

	Min	Most likely	Max
m per productive dry hole day	56.2	88.9	174.6

Table 3 Drilling Productive Time

In addition to the productive time estimation as per Table 6, the following additional time component estimates were added to wells as applicable:

Activity / Applicability	Time (days)	Comments
Crestal well Pilot Hole	2	Pilot hole required for shallow wireline data acquisition. Assume that the pilot hole is drilled from below conductor and then opened (no P&A). Does not include time to perform logging.
Crestal well Additional WL runs	4.1	Estimate assumes 10 WL runs, total 5 days Subtract the 0.9 days average WL logging included in offset data
Crestal well Coring	6	Estimate assumes 4 coring runs, total 1.5 days No coring included in offset data
Deviated well Additional WL runs	0.6	Estimate assumes 3 WL runs, total 1.5 days Subtract the 0.9 days average WL logging included in offset data

Table 4 Drilling Additional Productive Time

5.3.2 Completion

Information from de-constructed offset data. was used to generate a triangular distribution for productive completion time expressed in days per completion:

	Min	Most likely	Max
Days per Completion	9.6	20.6	34.2

Table 5 Completion Productive Time

5.3.3 Non-Well Activity

Not Applicable

5.4 Non-Productive Time

Information from de-constructed offset data was used to generate a triangular distribution for drilling and completion non-productive time expressed as a %:

	Min	Most likely	Max
% NPT	3.8	21.2	43.7

Table 6 Drilling Non-Productive Time

	Min	Most likely	Max
% NPT	0.0	23.3	49.4

Table 7 Completion Non-Productive Time

5.5 Scope Uncertainties

The events in Table 8 and associated probabilities were used to generate the Performance Target and Not to Exceed (NTE) estimates in the wells time and cost model:

Event	Probability	Time (min / most likely / max)	Fixed Costs ($ mm)	Comments
Wait on weather to move rig	0 – 0.25	7 / 14 / 21 days		Applicable to wells with rig moves
Side-track due to stuck pipe	0.2	6 / 10 / 14 days	1.0	
Losses while drilling	0.2	4 / 6 / 8 days		
Re-spud	0.2	4 / 6 / 8 days	1.0	
Major Rig Repairs	0.1	2 / 6 / 10 days		
Issue with DTS DAS installation	0.2	10 / 12 / 14 days	1.0	
Wait on Weather to install tree	0.2	1 / 14 / 21 days		

Table 8 Drilling and Completion Scope Uncertainties

5.6 Learning Curves

A learning curve was applied using the Brett-Millheim model with the following parameters:

- Drilling ratio of plateau to reference times: 75%
- Drilling learning rate: 30%
- Completion ratio of plateau to reference times: 75%
- Completion learning rate: 30%

Use of this model and parameters mean that there is the potential for drilling and completions performance to improve to 75% of the reference times by a reduction reducing the gap by 30% per well.

A learning curve was applied for the following reasons:

- There is a recognition that drilling offset data is predominantly from wells drilled between 2000 and 2008, so it is expected that performance on NZT/NEP could be improved (e.g. due to advances in drill bit technology)
- There is a recognition that bp do not have recent experience drilling subsea wells from a jack-up rig, so there is expected to be good potential for learning improvements even though the number of wells is small.

Note that given the small number of wells (5), the progress toward the 75% plateau is limited.

5.7 Schedule

For the purposes of this document and estimate, the order of drilling and start dates are assumed to be as per Table 9 below but remain subject to review and change.

Well / Project	Start Date	Duration (days)	End Date	Comments
Rig Move + CI1	01-Jul-2024	68	07-Sep-2024	
Rig Move + CI2	07-Sep-2024	64	10-Nov-2024	
Rig Move + CI3	10-Nov-2024	61	10-Jan-2025	
Rig Move + CI4	10-Jan-2025	59	10-Mar-2025	
Rig Move + CI5	10-Mar-2025	57	06-May-2025	Crestal observation well
Rig Move + OE1	06-May-2025	62	07-Jul-2025	
Project Total	01-Jul-2024	370	07-Jul-2025	

Table 9 NZT/NEP Well Construction Schedule

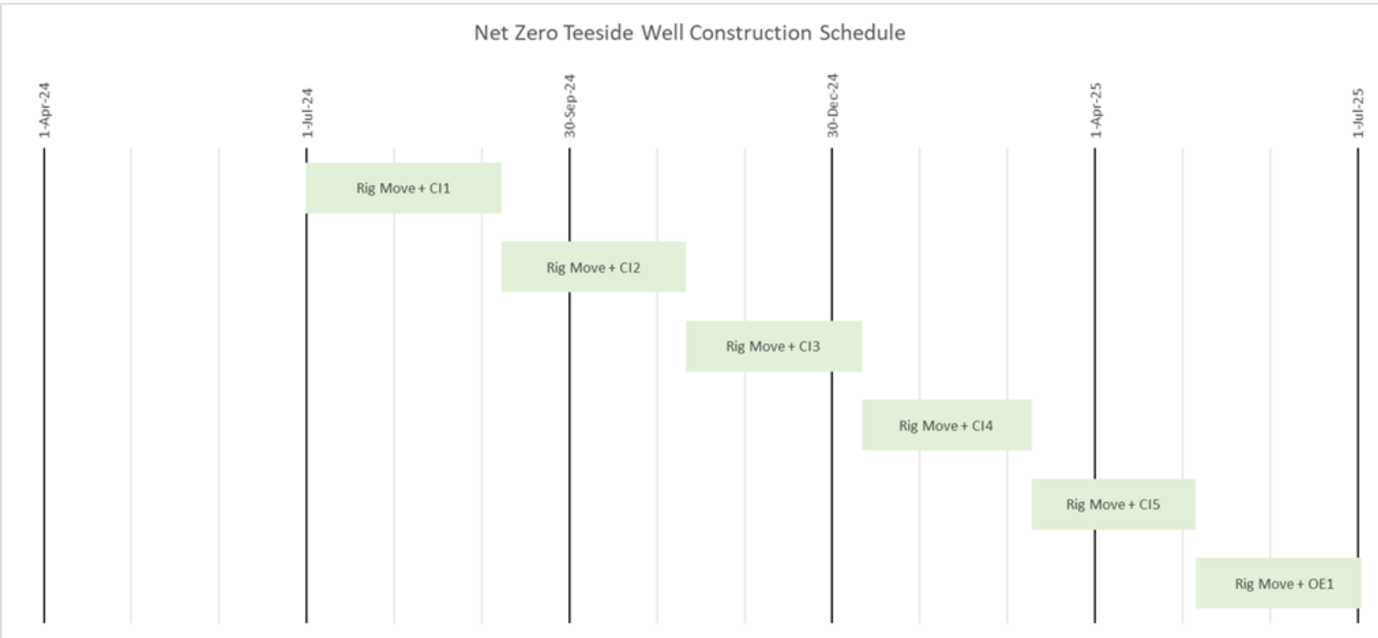


Figure 3 Provisional NZT/NEP Well Construction Schedule (subject to change)

6.0 Well Cost Estimate

The breakdown of well cost is as per the **Table 10** below:

Well	Cost ($mm)			Comments
	Base	PT	NTE	
Overall Project	191.8	217.8	255.2	
CI1	33.8	38.7	47.8	Includes initial rig move
CI2	32.6	37.1	45.5	Includes rig move
CI3	31.3	35.7	44.0	Includes rig move
CI4	30.8	35.0	42.8	Includes rig move
CI5	30.1	34.2	42.0	Includes rig move
OE1	32.3	36.2	44.0	Includes rig move, pilot hole and additional data acquisition (logging and coring)

Table 10 NZT/NEP Wells Cost Summary

6.1 Drilling and Completion Cost Basis

Drilling and completion costs were generated by considering typical and recent North Sea rig and service rates as well as typical costs for tangibles and rig verification. These individual rates and costs have been rolled up into an overall daily rate which covers the duration of the 5-well campaign.

6.2 Decommissioning Costs

Decommissioning costs are not included in this estimate.

6.3 Exchange Rates

This cost estimate has been calculated in USD ($). Where costs have been provided in GBP (£), an exchange rate of $:£ of 1.45 has been used

6.4 Inflation

No inflation has been applied to this well cost estimate.

6.5 DRILLEX Phasing

It is assumed that bp bring in one jack-up rig to drill all 6 NZT/NEP phase 1 wells in a single continuous campaign. As such, the DRILLEX phasing is as per the table below:

Year	2024	2025
Cost (PT)	$107mm	$111mm

Table 11 NZT/NEP DRILLEX Phasing

6.6 Cost Opportunities

The following cost opportunities were evaluated by adjusting the input data in the cost model and recording the impact of each for the overall project:

- Increasing drilling performance such that average 1Q offset days/10k performance is attained
- Increasing completion performance such that average 1Q offset days/completion performance is attained
- Eliminating pilot hole, coring and wireline data acquisition

Figure 4 illustrates the potential cost upside for the project.

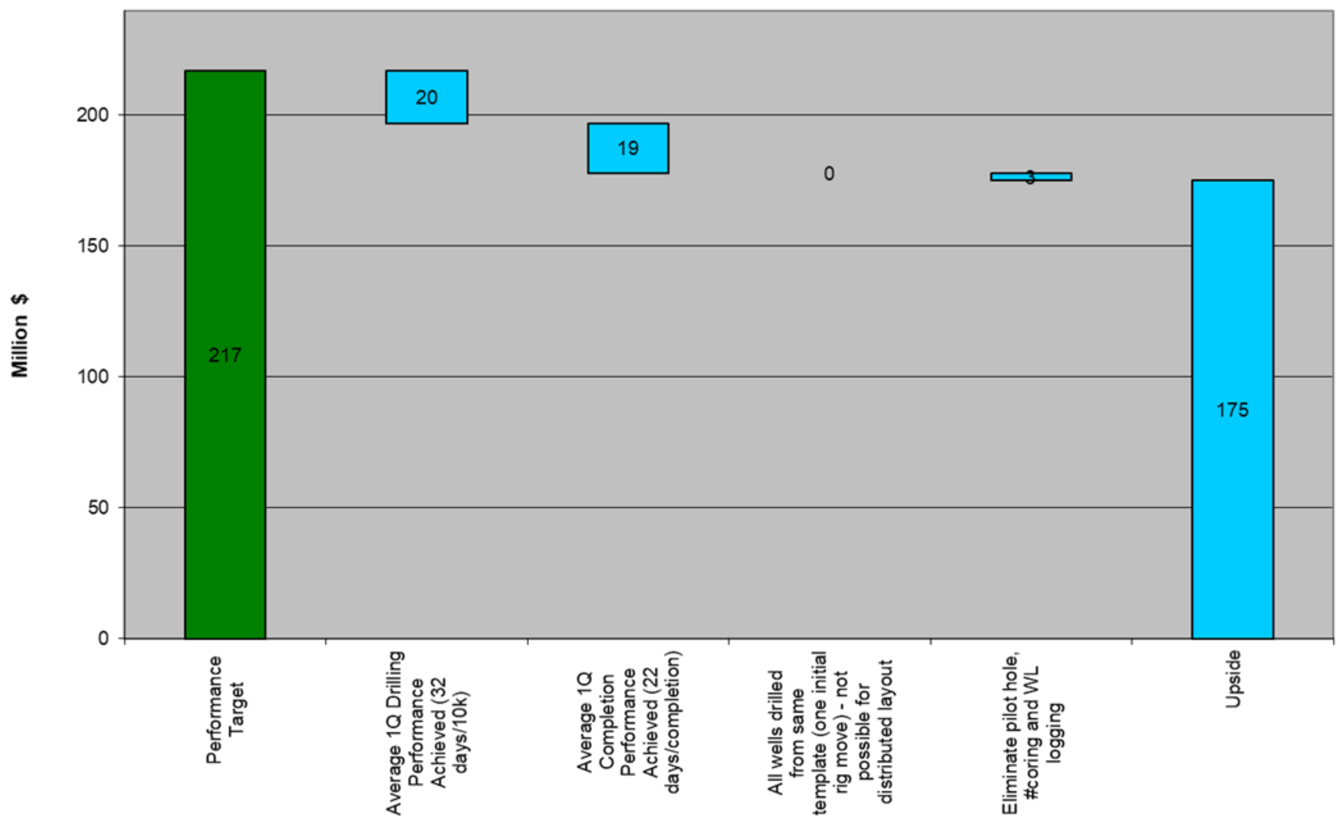


Figure 4 NZT/NEP Cost Opportunities

7.0 Benchmarks

7.1 Drilling Benchmarking

Figure 5 below shows the drilling offsets (as per Section 0) in yellow, and the performance target days/10k. It should be noted that the last NZT/NEP well (OE1) (the crestal observation well) has higher days/10k due to the inclusion of a pilot hole, and additional data acquisition (coring and wireline logging) required.

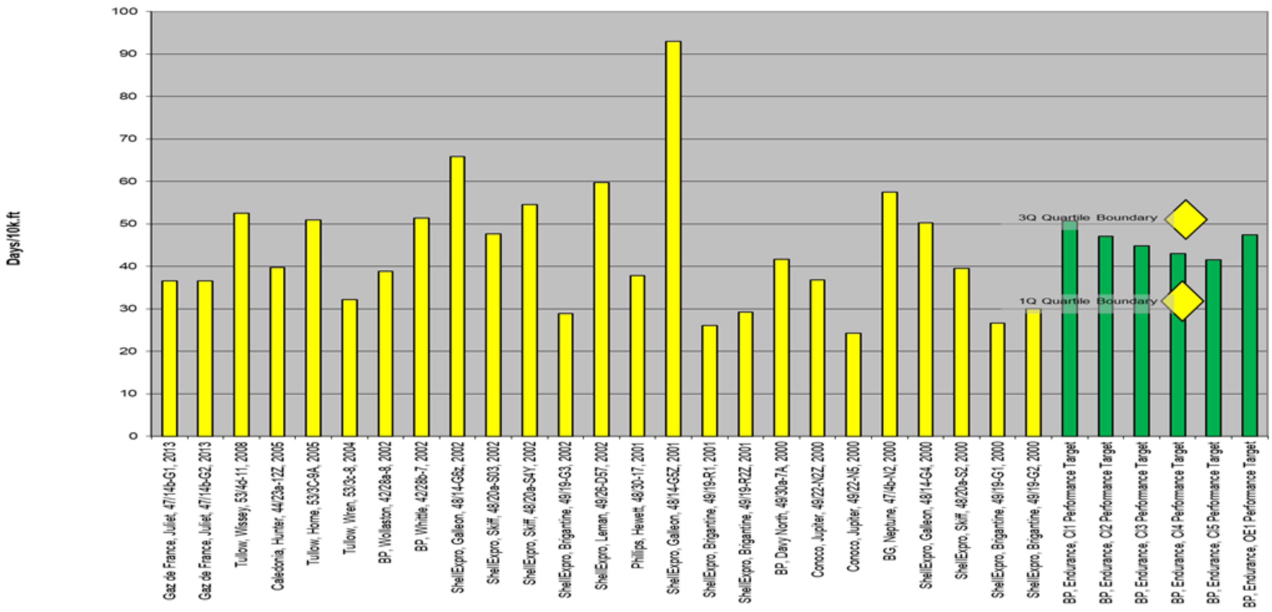


Figure 5 Drilling Benchmarking Plot

7.2 Completion Benchmarking

Figure 6 below shows the drilling offsets (as per Section 0) in yellow, and the performance target days/completion.

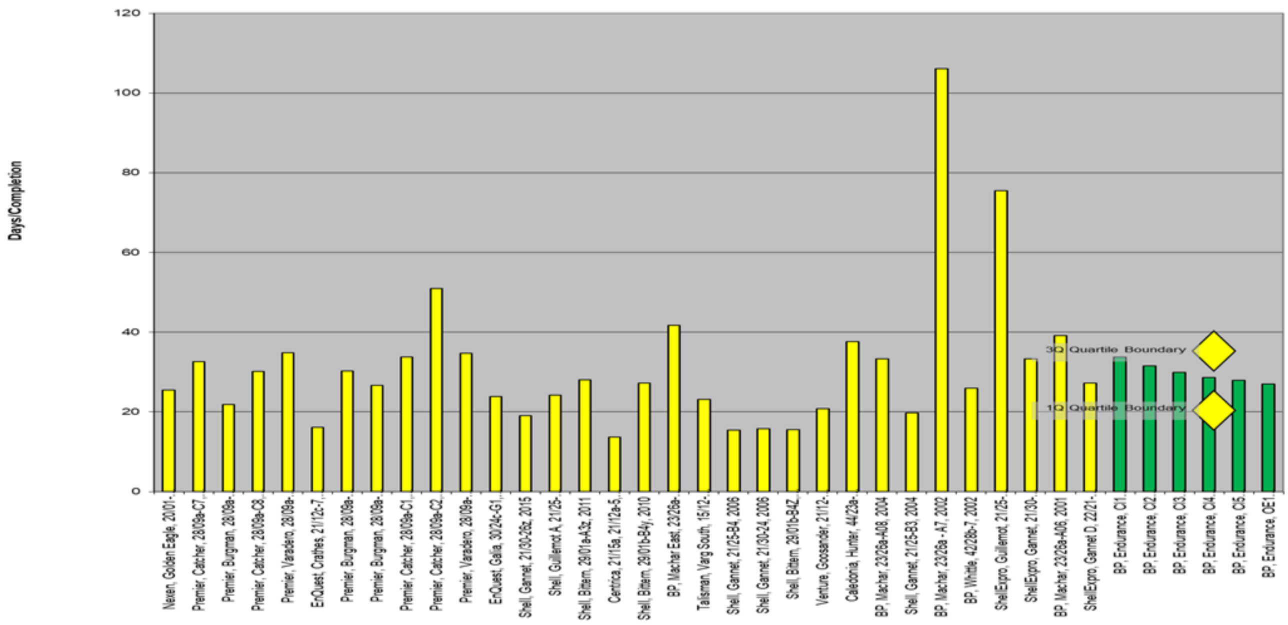


Figure 6 Completion Benchmarking Plot

8.0 Well Interventions and Ops Efficiency Forecast

8.1 Well Interventions and OPEX Forecast

The intervention forecast has been split into three sections:

8.1.1 Water Washing

A requirement exists to flush the near wellbore with fresh water. This will be done from a vessel set up to connect to either the tree or manifold in a similar manner to a scale squeeze, initially planned for one wash per well per year; however this is likely to extremely conservative, as based on analogues and planned base-load injection rate, the CO_2 – brine interface in the reservoir is likely to be flushed away from the near wellbore and potentially reduce or eliminate issues with halite deposition.

A fully-built up operations programme was developed to generate a cost and schedule for each yearly water washing campaign from a suitably-equipped support vessel. Duration and costs are slightly higher for a distributed (Inline-T) subsea architecture as the boat may have to move between wells.

A breakdown of the water-washing operations and OPEX can be found in **Table 12**.

8.1.2 Surveillance and Light Interventions

The planned surveillance programme is comprehensive and comprises a slickline drift run followed by a PLT in each injection well every 5 years. One RST saturation log is also included in the observation well as part of campaign. The surveillance plan has been devised to provide data that will be required by the regulator to monitor CO_2 movement in the reservoir – therefore an opportunity exists to build surveillance capability (e.g. fibre optics) into each well to minimise visits from the LWIV; however at this stage, the base case assumes a LWIV campaign every five years, and a comprehensive programme and cost basis has been developed based on current north sea region rates and experience.

As the planned surveillance programme is large, unplanned light interventions have not been included as by comparison they are much less frequent. It is assumed that any interventions required could be appended to the next planned campaign with the incremental cost not being significant.

A summary of the light well intervention surveillance operations and OPEX can be found in **Table 12**.

8.1.3 Workovers (Heavy Interventions from a Rig)

“Heavy” interventions involve a tubing pull – for example a safety valve change-out or for a packer leak or tubing repair.

A review of subsea interventions in BP predicted 0.01 heavy interventions per well per year (40 days per job, or 0.418 days per well per year), and this metric has been assumed for NZT/NEP at this stage.

A summary of the workover operations and OPEX can be found in Table 12.

Job	Subsea Layout	Deployment	Campaign Mean Cost	Campaign Mean Time	Mean Cost	Mean Time
Surveillance	Clustered	LWIV / SLS Wireline	$18.74MM	52 days	$624k / well / year	1.7 days / well / year
Surveillance	Distributed	LWIV / SLS Wireline	$19.73MM	55 days	$657k / well / year	1.8 days / well / year
Water Washing	Clustered	Vessel with Subsea Connection	$3.57MM	13 days	$595k / well / year	2.1 days / well / year
Water Washing	Distributed	Vessel with Subsea Connection	$4.56MM	17 days	$762k / well / year	2.8days / well / year
Workover	Either	Rig	$21.0MM	40 days	$220k / well / year	0.418 days / well / year

All equipment modifications, SITs and other fixed costs assumed to be amortised over five 5-yearly campaigns.

All water-wash equipment modifications, SITs and other fixed costs assumed to be amortised over twenty-five 1-yearly campaigns.

Workover cost uses $455k / day and completion tangibles

Table 12 Intervention Schedule and OPEX

8.1.4 Interventions and OPEX Summary

Using a distributed subsea layout as a conservative case (more vessel moves between wells), adding the relevant rows from **Table 12** gives the following average metrics:

- Intervention Operation Time: 5.018 days per well per year
- Intervention Operation OPEX: $1.63MM per well per year

Clearly water washing is the most significant contributor to intervention OPEX, and as explained above, there is the opportunity to reduce the frequency of washes depending on well operational experience.

This publication is available from: www.gov.uk/beis

If you need a version of this document in a more accessible format, please email enquiries@beis.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.