CATO-2 Deliverable WP 2.4-D02
Specifications for an improved version evaluation tool

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1 Executive Summary (restricted)

The development of CCS in NNL depends on the availability of both captured CO_2 and storage capacity. The growth curve of the captured CO_2 determines the speed at which consecutive storage locations need to be developed, while the location of storage capacity determines where transport routes are constructed. Where multiple storage locations are available, site choice becomes an economic decision. To ensure cost-effective development of CCS, a good understanding of options, cost and timing is required, to enable guidance and support from the government, as well as to provide all relevant information to industrial parties. Results such as those provided in the EBN/Gasunie report and in more detailed and longer-term studies as those to be delivered in CATO2 will help realise CCS.

This report is a first step to modelling of CCS development in North Netherlands. The aim is to extract the information required for modelling of the development on a longer timescale and in more detail than that provided in the EBN-Gasunie report; this modelling is foreseen for the remainder of the CATO2 program.

Information on storage capacity, injection rates and cost of storage and transport is derived from the EBN-Gasunie report, for both onshore and offshore CCS. As the EBN-Gasunie report was partly based on confidential data, and the work in the CATO2 program is done with publicly available data, a comparison is made between the data from the EBN-Gasunie report and the data available for the CATO2 work.

Distribution List

(this section shows the initial distribution list)

External	copies	Internal	Copies

Document Change Record

(this section shows the historical versions, with a short description of the updates)

Version	Nr of pages	Short description of change	Pages

Table of Content

2 Applicable/Reference documents and Abbreviations

2.1 Applicable Documents

(Applicable Documents, including their version, are documents that are the “legal” basis to the work performed)

	Title	Doc nr	Version date
AD-01	Beschikking (Subsidieverlening CATO-2 programma verplichtingnummer 1-6843	ET/ED/9078040	2009.07.09
AD-02	Consortium Agreement	CATO-2-CA	2009.09.07
AD-03	Program Plan	CATO2-WP0.A-D.03	2009.09.29

2.2 Reference Documents

(Reference Documents are referred to in the document)

	Title	Doc nr	Issue/version	date

2.3 Abbreviations

(this refers to abbreviations used in this document)

3 Introduction

Work package 2.4.2 of the CATO2 programme aims at providing a long-term outlook on the options for CCS in the regions near Rotterdam and near Eemshaven. In both regions, CCS projects for the period 2015 – 2020 are being planned, where depleted gas fields provide storage capacity for the demonstration projects.
This work package addresses the economic assessment of CCS projects comprising the entire CCS chain. Analysis is done by updating and applying an economic decision support system, a web-based tool that was developed in the EU Geocapacity project. The results of the full-chain analysis provide economic indicators, such as NPV, IRR, pay-back time etc for the full chain and individual components, as well as a detailed view on the uncertainties in the economics. For a number of local or regional CCS projects, an in-depth analysis of the CO_2 value chain is carried out.

The goal of this paper is to define the starting point for an extension of the calculations of EBN/GASunie study on the CO_2 storage and transport strategy for North of the Netherlands (NNL). In the present report, an overview is given of currently available planning study for CCS in the north and west regions. The Rotterdam region has been the subject of several recent publications that looked at the feasibility and longer-term options for CCS [1-4], while for NNL the longer-term options were only sketched [4]. For this reason, the current report focuses on NNL. However, the west Nethlerlands (WNL) strategy is also reviewed, as this strategy includes offshore storage and thus important cost data on the transport and cost of offshore transport and storage.

The most recent and detailed study of options for CCS in NNL and WNL were published in a report prepared and coordinated by EBN and Gasunie, covering both onshore and offshore Netherlands [4], referred to hereafter as the EBN/Gasunie report. The feasibility of CCS was studied with respect to geological limits (storage capacity, mainly in depleted gas fields), limits arising from the expected growth in captured volumes and economic limits.

In the preparation for the onset of CCS and to create the information basis for longer-term developments, a study like the EBN/Gasunie report – focussing on local situations - is a logical step after a national, or even international analysis of the options for CCS. Examples of the latter are the recent reports of options for CCS on a European scale [5, 6], on the scale of the North Sea, as published by the North Sea Basin Task Force [7] and on a national scale [8 – 10]. Local scale reports include those published by the Rotterdam Climate Initiative [11] and the ‘Kernteam CCS Noord-Nederland’ [12]. The latter two publications prepare for the local development of CCS projects.

The present report investigates the data that are available for an assessment of the feasibility and cost of large-scale CCS in NNL, with the aim to perform a study along the lines of ref. [3], which presents a similar study for offshore CCS in the Netherlands.

Section 4 presents the results for NNL that can be derived from the recent study by EBN/Gasunie. While the results from EBN/Gasunie are based partly on confidential data from the gas field operators, the present work is done with publicly available data of gas field capacity and availability. These public data are presented in Section 5 and, where possible, compared with those presented in EBN/Gasunie report. Section 6, finally, outlines the future analysis the options and cost of CCS in NNL within CATO2 with the CCS economic planning tool.

4 EBN/Gasunie study on CCS feasibility

Important input for a long-term economic optimisation or planning of CCS is to understand the major cost elements, for example the relation between storage capacity, the number of wells required and the cost of storage. It is also important to formulate a quantitative relationship between the amount of CO_2 transported, the transport pressure, the distance and the cost of transport. This is needed to update the cost modules in the economic optimisation tool that will be used in the second year of CATO2. As a starting point the data and costs relations presented in the EBN/Gasunie study[1] is analysed and converted is such a way that it can be used for our modelling tool.

In the sections below, the main quantitative results of the EBN/Gasunie report are shown, for both offshore and onshore transport and storage of CO2. We try to extract and explain data and relationships that can be used to update the evaluation tool. We present both data and results from the EBN/Gasunie study and the results of calculations we performed using this data. All white cells in the tables are original values reported in the EBN/Gasunie report. All highlighted (coloured) values in the tables, as well as all figures are calculated values.

4.1 Capture, transport and storage scenarios

The EBN/Gasunie study assesses the feasibility of CO_2 transport and storage in two main regions, West Netherlands (WNL) and North Netherlands (NNL). The growth of the capture efforts in the Netherlands and in near regions in for instance Germany determines the supply of CO_2 for storage for that region. The potential supply of CO_2 from Germany is not included in the study.

Both the cost data and assumptions for NNL and WNL are relevant for updating the evaluation tool as these the EBN/Gasunie study uses different cost data and assumptions for these regions. These differences relate to the amount of CO2 captured, transported and stored. Another clear difference is that the WNL region uses only offshore storage capacity and the NNL region only onshore storage capacity. The transport trajectories are therefore also predominantly offshore in the WNL region and onshore in the NNL region. This will consequently result in different cost assumptions and results for transport and storage. These differences are important when updating the evaluation tool. More details on the difference between the feasibility studies for the NNL and WNL regions are presented in Table 1.

The projected growth of CCS activities in NNL according to the McKinsey scenarios (Base and Green) used in the EBN/Gasunie study is shown in Figure 1 and Table 1. The ‘Base scenario’ projects a more ambitious growth in capture efforts and increases from 1 million tonnes of CO_2 in 2020 to almost 20 million tonnes of CO_2 by 2050. A ‘Green scenario’ is defined in the McKinsey report as one in which a smaller CCS effort is required to reach CO_2 emission reduction goals. In the Green scenario the volume of CO_2 is about 8 million tonnes of CO_2 by 2050.
In figures onder it is shown that the amounts of CO_2 captured and stored are significantly larger for the WNL region than for the NNL region (the scenarios for WNL are shown in Figure 2 and 3).

[1] The EBN/Gasunie study is based on a recent report of offshore CCS cost [13], and uses data on onshore transport as provided by Gasunie. The latter data, relevant to the present study, are not always explicitly given in [4].

In addition to the Base and Green scenarios also variants to these scenarios are developed. For the NNL, so-called Base 1 and 2, and Green 1 and 2 variant were developed. It is however not specified in the EBN/Gasunie report what these variants exactly include and how they differ from the 'normal' Base case.

Table 1. Overview of main scenarios assessed in the EBN/Gasunie study

Region	Scenario	Additional variants	Onshore/ offshore	Total storage in 2050 (Mt)	Maximum annual storage (Mt/yr)
North Netherlands	Base	Base 1* Base 2	Onshore	345	1-20
	Green	Green 1 Green 2	Onshore	170	8
West Netherlands	Base	Base optimized**	Offshore (predominantly)	955	2-55
	Green		Offshore (predominantly)	345	24

* The base 1&2 and Green 1&2 are variants of the base and green scenarios. How they precisely vary from the Base and Green scenarios is not reported.
** Optimized variant includes more efficient use of injection facilities and less use of smaller reservoirs (P18 and Q8)

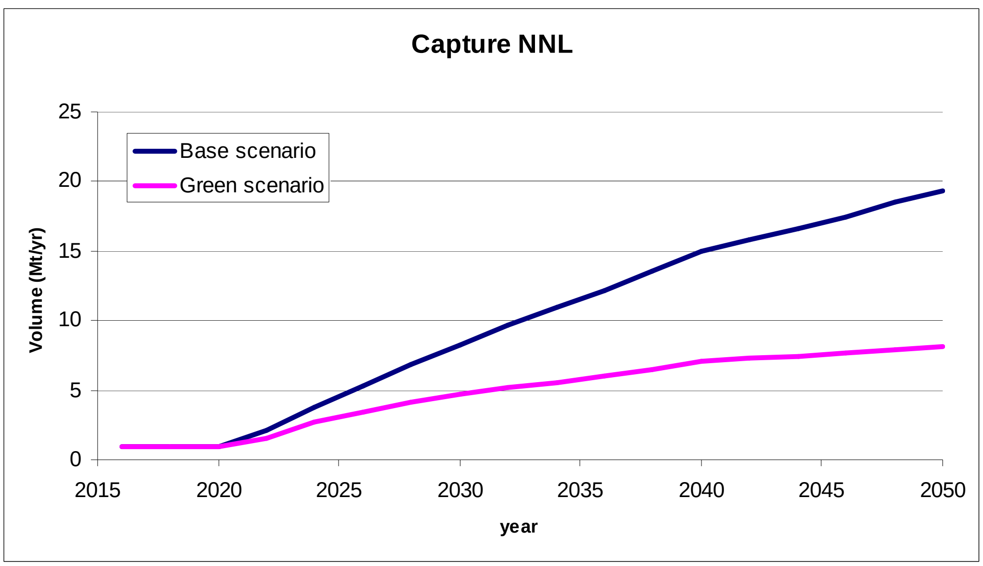

Figure 1. Capture scenario used for NNL. The volume of CO_2 is projected to grow from 1 Mt/yr in the period 2015 – 2020, to 20 Mt/yr by 2050 for the 'Base scenario' and 8 Mt/yr in the 'Green scenario'.

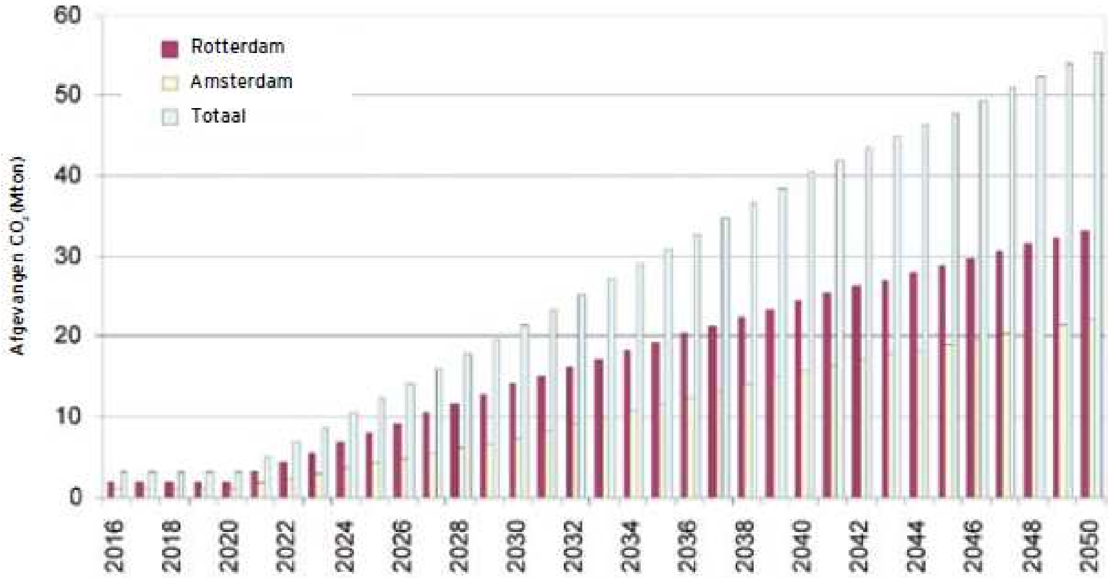

Figure 2. Capture Base scenario used for WNL. The volume of CO_2 is projected to grow from 2 Mt/yr in the period 2015 – 2020, to 55 Mt/yr by 2050

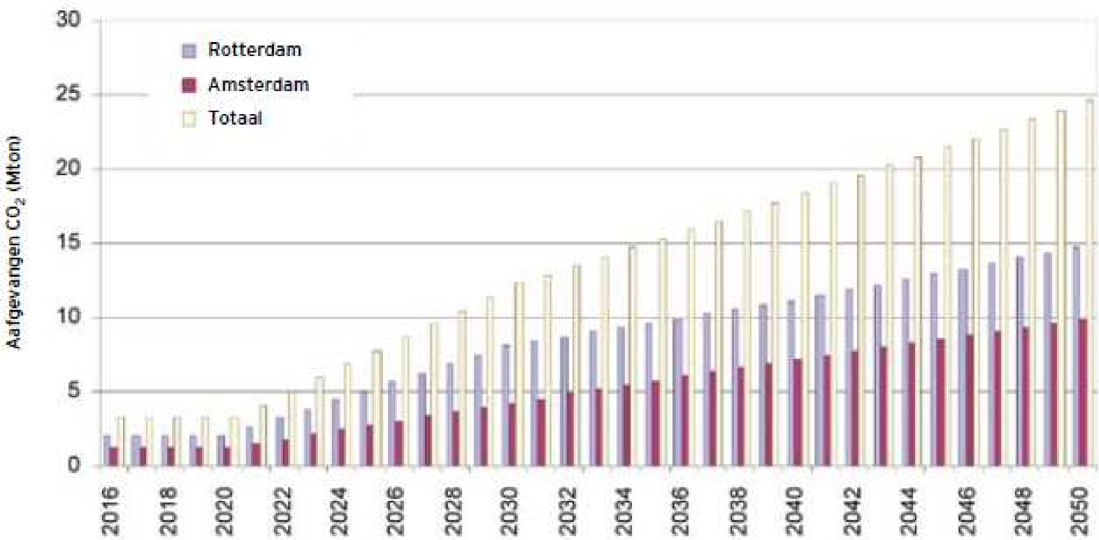

Figure 3. Capture Green scenario used for WNL. The volume of CO_2 is projected to grow to 24 Mt/yr by 2050

4.2 Transport cost

The costs can be divided into capital expenditures (CAPEX) and operational expenditures (OPEX). CAPEX for CO_2 transport includes the costs for the pipeline (ship transport is not included here) and compressors to compress the captured CO_2 to the required transport pressure.

OPEX for the transport includes the cost for operation and maintenance for the pipeline infrastructure, the operation and maintenance for compression and the energy costs. Both CAPEX and OPEX depend heavily on the amount of CO_2 transported, the required transport pressure and the transport distance.

The energy cost for compression form a dominant part of the OPEX and it highly depends on the pressure of the CO_2 after the capture step and the required transport pressure. In the EBN/Gasunie report, the CO_2 is assumed to become available at atmospheric pressure after capturing the CO_2 from point sources. The required transport pressure depends typically on the transport distance and consequently differs for the offshore and onshore scenarios and thus for the WNL and NNL scenarios. The onshore transport pressure is about 40 bar, with the CO_2, at ambient temperatures, in the gas phase. The transport pressure for offshore transport is assumed to be at least 75 bar, with the CO_2 in the dense phase. The exact transport pressures are however not mentioned in the EBN/Gasunie report.

The costs of CO_2 transport via pipeline are presented for both on- and offshore pipelines in the tables below. The EBN/Gasunie report lists the total transport and compression CAPEX and OPEX. The CAPEX reported reflects the total amount of capital required over the full period of the scenario, i.e. up to 2050. The CAPEX is calculated using a discount rate of 0%. OPEX for transport and compression are presented as annual expenditures. It is however not specified for which view years the OPEX are valid.

This information is nevertheless used together with the amount of CO_2 transported listed in Table 1 to calculate the Unit Technical Cost (UTC) per tonne of CO_2 compressed and transported. The CAPEX per tonne of CO_2 is calculated by dividing the total CAPEX in a scenario by the total amount of CO_2 transported in a scenario. The OPEX per tonne is calculated by dividing the annual OPEX by the *maximum* amount of CO_2 transported annually (i.e. amount of CO_2 in year 2050), as reported in Table 1. Based on the data available, a range for the cost per tonne of CO_2 was calculated; see Table 2 (onshore) and Table 3 (offshore). For offshore transport and compression cost an additional difficulty arises as the EBN/Gasunie report does not specify for which scenario the total CAPEX and OPEX are reported. The UTC are therefore calculated using the transport flows of both scenarios, see Table 3.

For the development of the evaluation tool it is also necessary to derive a relationship between transport distance and the UTC for transport & compression. The tables do not show the total transport distance as this is not provided in ref. [4], rendering the computation of the CAPEX in €/km impossible. A relationship between transport distance and CAPEX and OPEX could thus not be derived.

The results of calculating UTC for compression and transport show that total UTC (transport and compression) summing CAPEX and OPEX is about 10-11 € for onshore and ranges between 6 and 14 € for offshore. It is however unclear in the report whether the total cost refer to the base or green scenario. It is thus also unclear which scenario should be used to calculate UTC for CO_2 transport. The main reason why the CAPEX share of the UTC could be lower in the offshore scenario is the volume of CO_2 transported. Secondly, the EBN/Gasunie report indicates that CO_2 is onshore transported below 40 bars, based on the consideration of limited transport distances. As mentioned earlier, the costs of transport depend strongly on the pressure, flow and distance of the CO_2. Typical trade-offs between cost (OPEX & CAPEX) of compression and pipeline infrastructure costs are present. In the evaluation tool it is necessary to minimize transport and compression cost and incorporate a cost module that chooses transport pressures depending on a cost calculation including the relationships between these trade-offs.

Table 2. Transport cost onshore in total cost and €/tonne (numbers in green cells are own calculations based on input from the EBN/Gasunie report).

Scenario	CAPEX		OPEX/yr		Total UTC (CAPEX&OPEX)	
	transport	compression	transport	compression	transport	compression
Total cost in M€ Base case	250	500	5	150		
Total cost in M€ Green case	100	250	3	70		
UTC in €/tonne Base case	0.72	1.45	0.26	7.89	0.99	9.34
UTC in €/tonne Green case	0.59	1.48	0.35	8.24	0.94	9.71

UTC CAPEX is calculated as total cost divided by total CO_2 *transported (and stored). OPEX UTC is calculated as annual cost divided by maximum annual transported volume.*

Table 3. Transport cost offshore in total cost and €/tonne (numbers in green cells are own calculations based on input from the EBN/Gasunie report).

Scenario	CAPEX		OPEX/yr		Total UTC (CAPEX&OPEX)	
	transport	compression	transport	compression	transport	compression
Total cost in M€	700	800	10	250		
UTC in €/tonne (if using base case scenario	0.73	0.84	0.18	4.50	0.91	5.34
UTC in €/tonne (if using green scenario)	1.48	1.69	0.41	10.16	1.89	11.85

Both base case scenario (cumulative 955 Mt in 2050) and green scenario (cumulative 473 Mt in 2050) assumed when calculating the transport CAPEX cost per tonne CO_2*. OPEX UTC is calculated as annual cost divided by maximum annual transported volume in respectively the base and green scenario.*

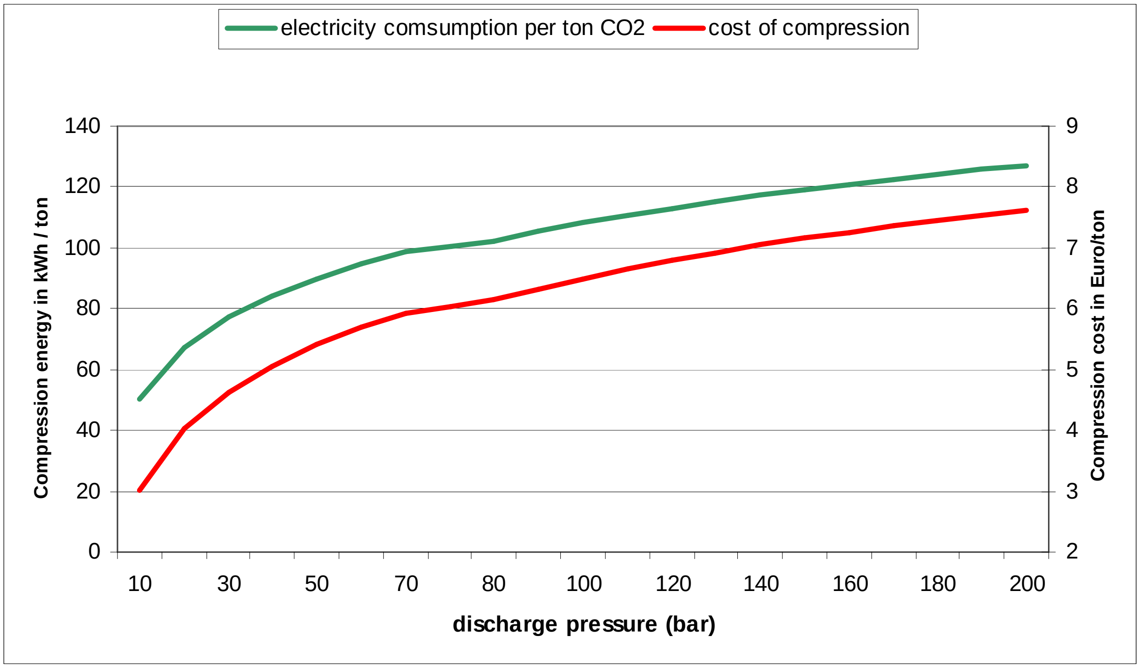

Figure 4. Calculated energy cost for compression (own calculation based on compression model assuming energy cost of 60 euro/MWh).

As mentioned earlier, the energy cost for compression represent a large share in the total OPEX for compression. A specification of these costs is not presented in the EBN/Gasunie report and a further breakdown of compression OPEX is not given. As the compression OPEX for onshore storage seemed high, we performed a check with own calculations for the energy cost of compression UTC. Compression energy cost is calculated based on our in-house compression model, but using the same price of power of 60 € per MWhe as assumed in the EBN/Gasunie report. This yields 5.1 €/tonne for onshore transport (for the low pressure of 40 bar). This is significantly lower than the figure of about 8 €/tonne reported in the EBN report. The difference could be explained by the operation and maintenance part of compression OPEX, which is then about 3 €/tonne. Typically annual O&M is about 6% of CAPEX for such equipment. A quick calculation shows that this 6% (of a total CAPEX of 500 M€) equals about 1.6-1.8 €/tonne. This renders about 1 €/tonne unexplained, but, considering the rough assumptions that have been done to estimate these costs, this is a good result.

Compression cost for the offshore scenario are calculated at about 6 €/tonne (@75 bar) as transport pressures are higher (typically above 75 bar; however no specific pressure is mentioned in the report). When compressing to 100 bar the cost are somewhat higher, 6.5 €/tonne. In the EBN report, OPEX UTC for compression may be between 4.5 and 10 €/tonne.The lowest value of 4.5 €/tonne seems unlikely as this value is lower than the energy cost calculated here.

Taking the highest value of the range between 4.5 and 10 would result in OPEX for operation and maintenance of about 4 €/tonne. With the same rough calculation as presented above, the 6% of total CAPEX (800 M€) would result in 1-2 €/tonne. This thus renders about 2 – 3 €/tonne unexplained.

Overall, the difference in results thus cannot be exactly verified or explained correctly as there is no more detailed breakdown of cost presented for transport and compression OPEX in the EBN report as presented in Table 2 and Table 3. It is therefore recommended to consult EBN/Gasunie on the specific assumptions they made to make an update of the evaluation tool possible.

4.3 Storage cost

In the EBN-Gasunie study, the cost of storage is broken down into the CAPEX and OPEX needed for the injection facility. The cost breakdown varies between offshore or onshore storage locations but also between individual reservoirs. The capacity of the reservoir, the amount of wells and the time span of injection are also expected by us to influence the overall storage cost.

In the EBN/Gasunie report the storage cost are presented for both on- and offshore injection in the WNL and NNL regions. The same scenarios as presented in Table 1 are used to calculate the costs for storage. In the EBN/Gasunie report, total CAPEX is reported for the total period up to 2050. OPEX are also presented for the entire period but not per year, as for the transport and compression cost. This influences the calculation methodology we applied for determining the UTC for storage, i.e. to calculate OPEX UTC we used also the total amount of CO_2 stored.

For the update of the evaluation tool it is necessary to include a relationship between the storage capacity per reservoir, amount of wells, the annual injection capacity and the costs. We therefore use the EBN/Gasunie report to estimate the CAPEX and OPEX per well. In combination with a typical injection capacity per well we can make calculations in the tool to estimate the CAPEX and OPEX per tonne of CO_2.

Below an overview of storage cost for both onshore as offshore locations are presented. This includes major assumptions that were reported in the EBN/Gasunie report to calculate the cost.

4.3.1 Onshore storage cost

In Table 4, Figure 5 and Figure 6, onshore storage cost assumptions are presented. These numbers are based on data reported in the scenarios for NNL in the EB/Gasunie report. The data shows that 'conversion' and 'abandonment' of the platform and wells are important cost elements. Furthermore, we see declining cost per well when increasing the number of wells for the cost elements 'conversion' and 'abandonment'. For 'mothballing'[2] the specific cost per well decreases also when using multiple wells. The other cost elements are independent of the total number of wells.

Table 4. Onshore injection cost in M€ (numbers in green cells are own calculations based on input from the EBN/Gasunie report)

	Cost type	**Total**			**Per well**		
Injection phase	**# wells**	**5**	**2**	**1**	**5**	**2**	**1**
mothballing	CAPEX	2.6	1.4	1	0.5	0.7	1.0
mothballing	OPEX	0.1	0.08	0.05	0.02	0.04	0.05
Conversion production -->injection	CAPEX	10.9	5.5	3.7	2.2	2.8	3.7
CO_2 injection	OPEX FUEL	3	1.2	0.6	0.6	0.6	0.6
CO_2 injection	OPEX OTHER	7.5	3	1.5	1.5	1.5	1.5
Workover - once every 5 year	OPEX	7.5	3	1.5	1.5	1.5	1.5
Abandonment	CAPEX	10.1	4.4	2.5	2.0	2.2	2.5

Cost per well are cost divided over the number of wells for an onshore injection facility.

[2] The term mothballing refers to the period between the end of production and start of injection, during which the installations are maintained.

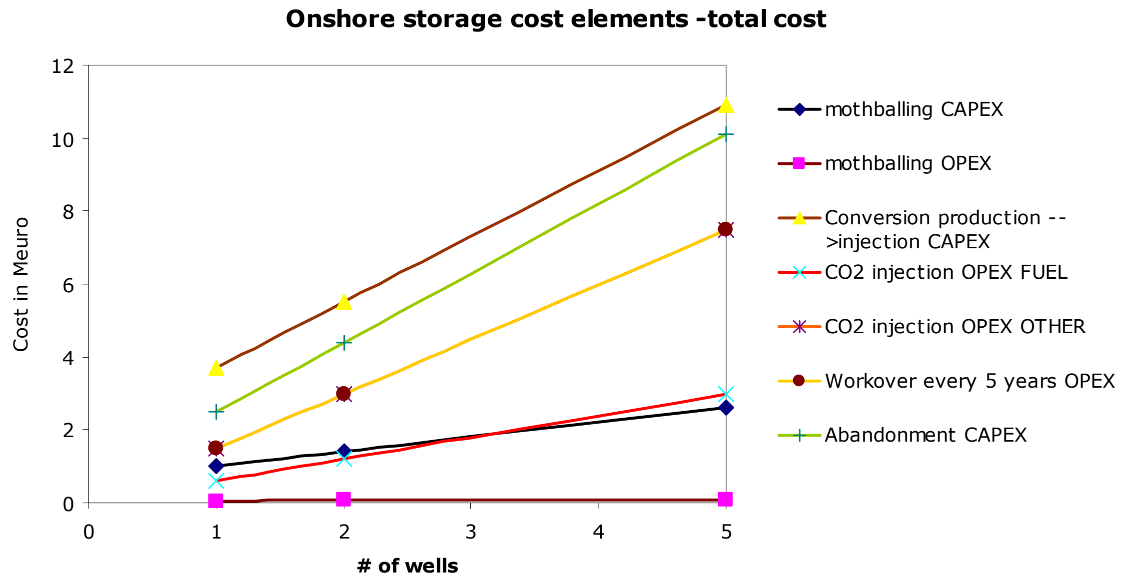

Figure 5. CAPEX and OPEX cost elements for onshore injection of CO_2. Cost depends on the phase of the injection project (mothballing, conversion, injection, workover and abandonment) of the injection facility and can be annual cost or cost made every five years (workover OPEX).

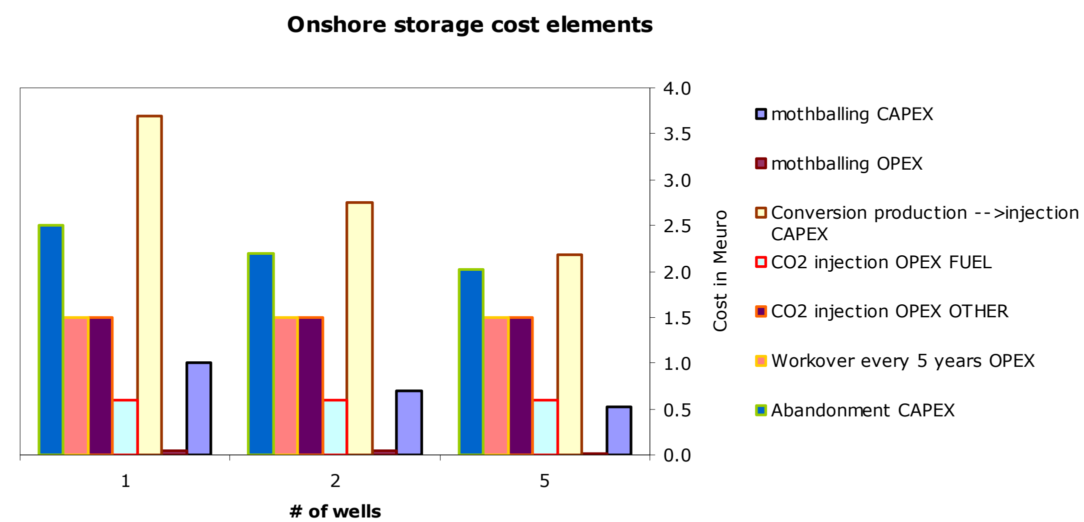

Figure 6. CAPEX and OPEX cost elements per well for onshore injection of CO_2. Cost depends on the phase of the injection project (mothballing, conversion, injection, workover and abandonment) of the injection facility and can be annual cost or cost made every five years (workover OPEX).

Table 5. Storage cost for onshore injection for various scenarios in total cost and €/tonne (numbers in green cells are own calculations based on input from the EBN/Gasunie report)

storage cost	CAPEX	OPEX	Correction	Total	CAPEX	OPEX	Correction	Total
	Total cost in M€				UTC in €/tonne			
Base case 1	134	424	262	821	0.39	1.23	0.76	2.38
Base case 2	86	338	360	784	0.25	0.98	1.04	2.27
Green scenario 1	104	344	6	454	0.62	2.04	0.04	2.69
Green scnario 2	41	421	-3	458	0.24	2.49	-0.02	2.71

UTC CAPEX is calculated as total cost divided by total CO_2 *stored. UTC OPEX is calculated as total OPEX divided by total* CO_2 *stored. The so called 'Correction' is not specified in the EBN/Gasunie report. There is also no reference to a report where such a 'correction' is applied nor what it specifically includes*

In Table 5, the total cost of the onshore storage scenarios is reported. Also, the UTC in €/tonne is calculated for the different scenarios. The average UTC for the scenarios is estimated between 2 and 3 €/tonne CO_2.

In Figure 7, the specific UTC storage cost are presented for a selection of 6 reservoirs. In the scenarios more reservoirs are utilized, but these are not shown separately in the report. The data show a range between 1.8 and 4.1 € per tonne of CO_2 stored. The costs varies per reservoir, but also by deployment scenario as it determines how much CO_2 is annually and cumulative stored in a certain reservoir. In some scenarios, the capacity of the storage reservoir is not completely utilised which results in higher UTC compared to the situation of full capacity usage.

No general relationship showing economies-of-scale can be derived from the data presented in the EBN/Gasunie report. From this data it could not be concluded that reservoirs with a higher storage capacity necessarily lead to lower storage cost, although the lowest storage cost are found for the largest reservoir. From the cost assumptions presented above we would expect to find economies of scale as the cost for injection do not linearly scale with the amount of wells, and wells can be used as a proxy for annual injection capacity. A larger storage reservoir would typically be able to accomodate more wells and thus more CO_2 can be injected annually. Other factors may however also be dominant. An example may be the assumed time span for injection or the exact numbers of wells used per reservoir.

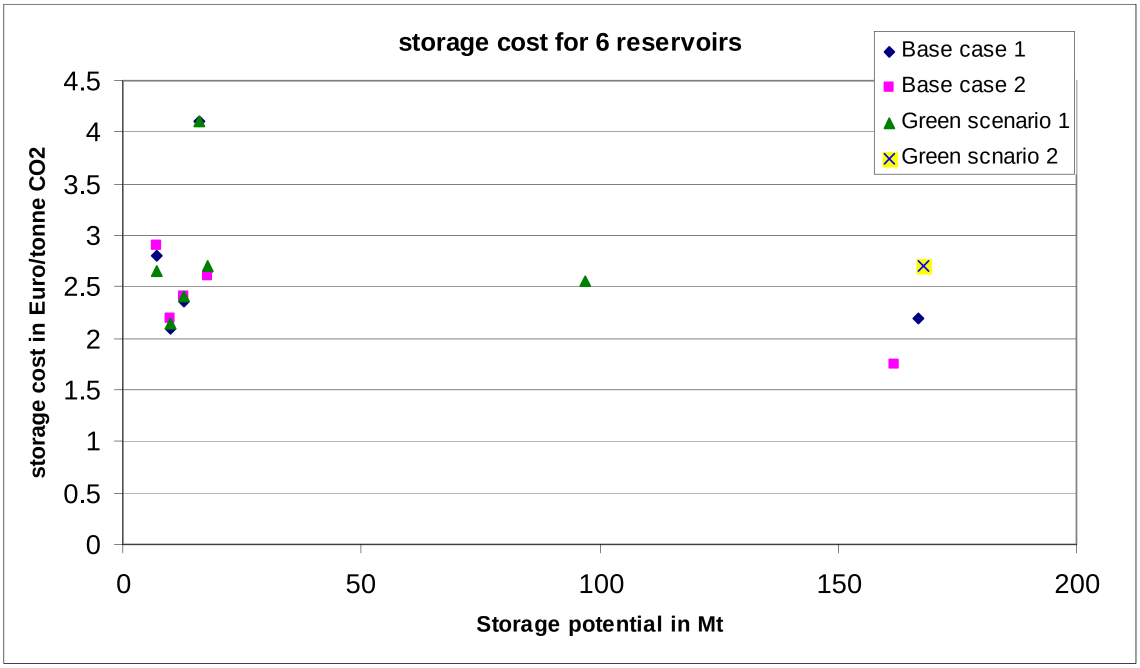

Figure 7. Onshore storage cost for 6 reservoirs in N-Netherlands. Vertically aligned points reflect one storage reservoir under certain scenarios

Table 6. Estimated storage capacity in Mt for 6 onshore reservoirs, also shown in Figure 7

Reservoir	A	B	C	D	E	F	Total
Storage capacity	Storage capacity in Mt CO_2						
Base case 1	7	10	13	16	18	167	231
Base case 2	7	10	13	na	18	162	210
Green scenario 1	7	10	13	16	18	97	161
Green scenario 2	7	10	13	na	18	168	216
Storage cost	UTC in €/tonne						
Base case 1	2.8	2.1	2.35	4.1	2.65	2.2	
Base case 2	2.9	2.2	2.4	na	2.6	1.75	
Green scenario 1	2.65	2.15	2.4	4.1	2.7	2.55	
Green scenario 2	na	na	na	na	na	2.7	

These figures were read from a graph in the EBN/Gasunie report. Values may thus not be completely accurate.

4.3.2 Offshore injection cost

Offshore injection cost are shown here, which are based on the data used for scenarios for West Netherlands in the EBN/Gasunie report. In Figure 8 and Figure 9, CAPEX for offshore storage facilities are shown, both as total cost and cost per well. Figure 9 shows that all cost per well decline rapidly with increasing number of wells, with the exception of tie-back costs. Overall construction costs increase linearly with the number of wells for this cost element. Given these numbers we would expect to see economies of scale for the CAPEX for offshore storage.

The EBN/Gasunie report does not report to what extent injection capacity increases when using multiple wells. We can roughly estimate the annual injection rate per well by using one quote from the report that states that the P18 cluster with an annual capacity of 4.1Mt uses 1 satellite platform with 6 wells serving 3 reservoirs with a total capacity of 40 Mt. This implies that the capacity of one well is 0.7 Mt per year (4.1/6). **Table 7** summarizes the data.

Table 7. Capacity details of the P18 cluster. (numbers in green cells are own calculations based on input from the EBN/Gasunie report).

wells	#	6
satellite platform	#	1
storage capacity	Mt	40
Annual injection capacity	Mt/yr	4.1
injection per well	Mt/yr	0.7

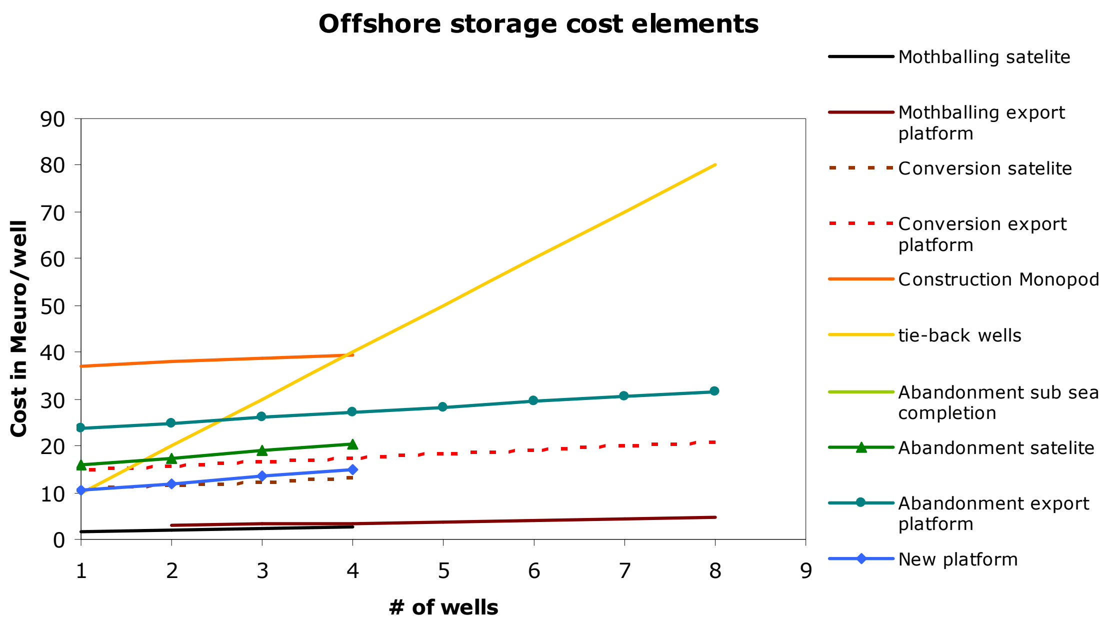

Figure 8. CAPEX for several cost elements of offshore injection. Note that this figure does not show OPEX.

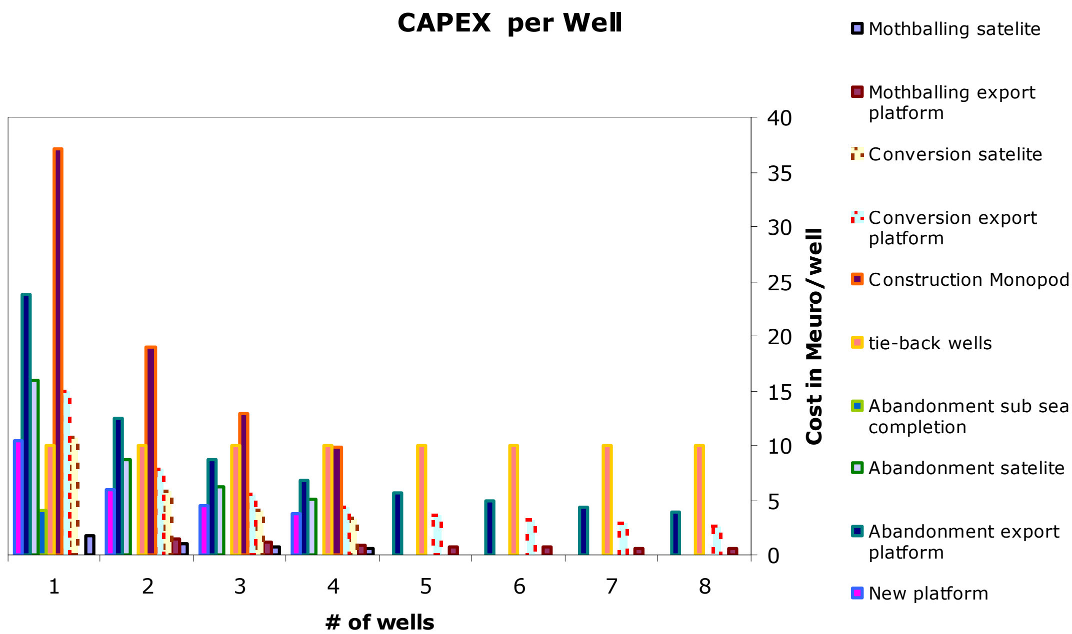

Figure 9. Offshore CAPEX for injection per well

Table 8 CAPEX offshore total cost in M€

	Wells #	**8**	**7**	**6**	**5**	**4**	**3**	**2**	**1**
Process	**type platform**								
Mothballing	satellite					2.6	2.3	2	1.7
Mothballing	export platform	4.6	4.3	4	3.8	3.5	3.3	3	
Conversion	satellite					13.3	12.3	11.5	10.7
Conversion	export platform	20.8	20	19.1	18.3	17.4	16.6	15.7	14.9
Construction	Monopod					39.5	38.7	37.9	37.1
tie-back wells		80	70	60	50	40	30	20	10
Abandonment	sub sea completion								4
Abandonment	satellite					20.4	18.9	17.4	15.9
Abandonment	export platform	31.6	30.5	29.4	28.2	27.1	26	24.9	23.7
New platform						15	13.5	12	10.5

Table 9. CAPEX offshore cost per well in M€ (numbers in green cells are own calculations based on input from the EBN/Gasunie report)

	Wells #	8	7	6	5	4	3	2	1
process	**type platform**								
Mothballing	satelite					0.7	0.8	1.0	1.7
Mothballing	export platform	0.6	0.6	0.7	0.8	0.9	1.1	1.5	0.0
Conversion	satelite					3.3	4.1	5.8	10.7
Conversion	export platform	2.6	2.9	3.2	3.7	4.4	5.5	7.9	14.9
Construction	Monopod					9.9	12.9	19.0	37.1
tie-back wells		10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Abandonment	sub sea completion								4.0
Abandonment	satelite					5.1	6.3	8.7	15.9
Abandonment	export platform	4.0	4.4	4.9	5.6	6.8	8.7	12.5	23.7
New platform						3.8	4.5	6.0	10.5

Table 10. OPEX per platform

Hibernation	Satellite	0,7
Hibernation	export platform	1,5
Injection	Satellite	3,2
Injection	Export platform	11,4
Injection	Monopod new	3

In Table 8, Table 9 and Table 10 the detailed cost data (CAPEX and OPEX) are also shown.

In the EBN/Gasunie report a distinction is made between certain blocks in which storage reservoirs or clusters of reservoirs are located in the North Sea. EBN/Gasunie reports separately for the P and Q blocks and the K and L blocks. In the base and green scenarios only the P and Q blocks are included. In Figure 11, Figure 12 and Figure 13 show the resulting UTC for a selection of clusters within the P and Q blocks under various scenarios (Base, Green and Optimized). The difference between the figures is determined by the scenario that is used to calculate the amount of CO_2 stored and the total cost. In these figures, also the OPEX is included for offshore storage reservoirs. We can see in the figures that the lowest storage costs are found for the larger storage reservoirs or clusters. We also expected this based on data reported in Figure 8 and Figure 9, but overall there is no conclusive evidence for economies of scale based on the results presented in the EBN/Gasunie report.

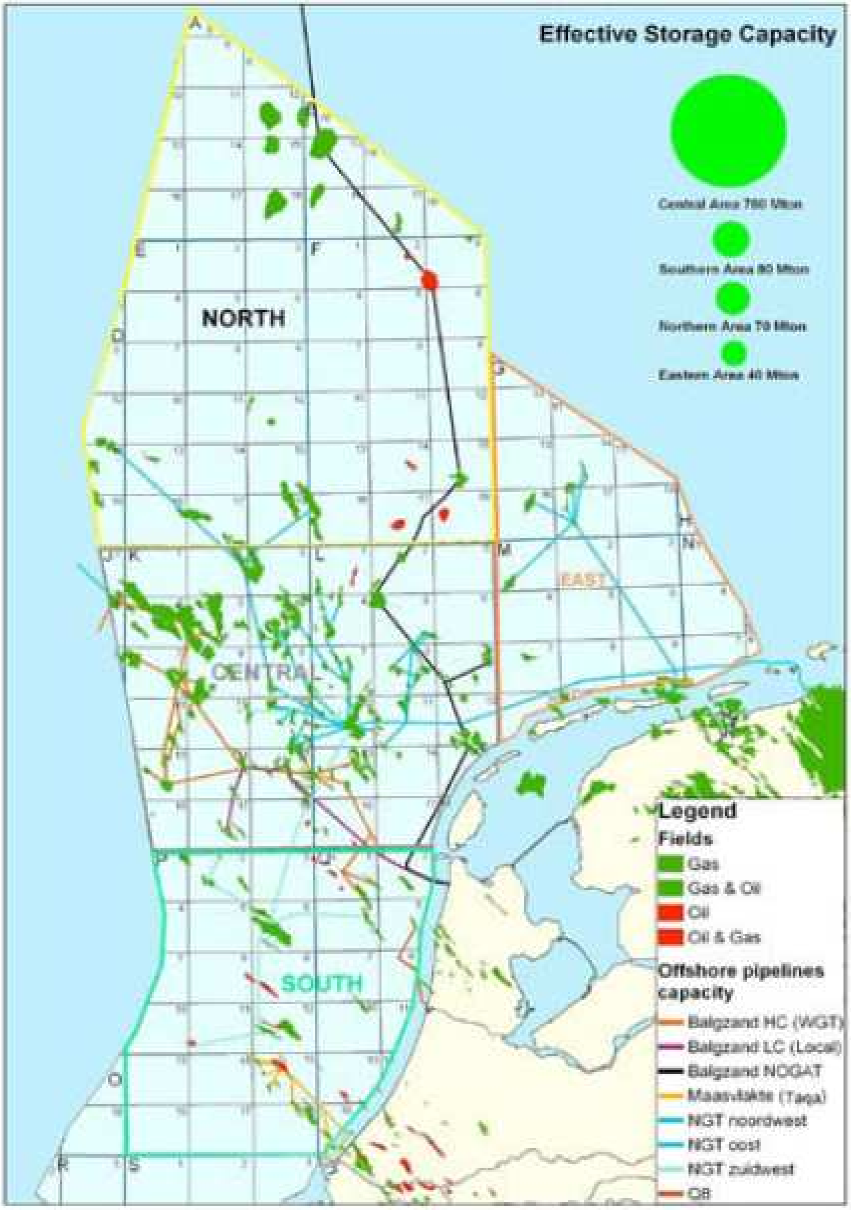

Figure 10. Offshore storage blocks and clusters

The maximum and minimum UTC for the P and Q blocks various scenarios are presented in Table 11 and Table 12. The results show that UTC (including OPEX and CAPEX) ranges between 2 and 14 €/tonne CO_2. These costs vary considerably per cluster. Clearly, offshore clusters P18 and Q1 in Table 11 show to have overall lower storage cost compared to the other clusters.

Table 11. Minimum offshore UTC storage cost in €/tonne (numbers in green cells are own calculations based on input from the EBN/Gasunie report)

		Cluster				
	unit	**P18**	**P15**	**P06**	**Q01**	**Q08**
UTC CAPEX	€/tonne	1.0	3.7	3.7	0.7	3.4
UTC OPEX	€/tonne	1.6	4.8	5.1	1.2	4.4

Table 12. Maximum offshore UTC storage cost in €/tonne. (numbers in green cells are own calculations based on input from the EBN/Gasunie report)

		Cluster				
	unit	**P18**	**P15**	**P06**	**Q01**	**Q08**
UTC CAPEX	€/tonne	1.0	4.6	4.5	1.5	3.4
UTC OPEX	€/tonne	1.6	5.1	9.5	2.2	4.4

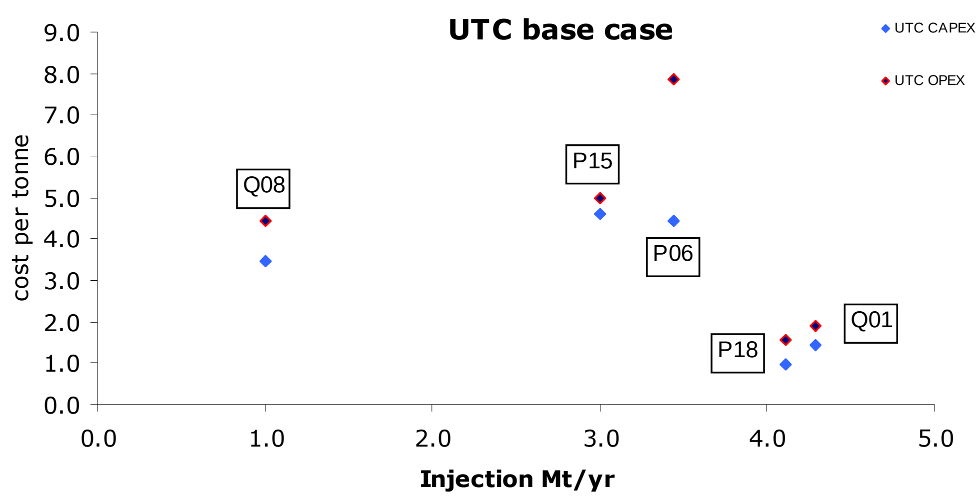

Figure 11 Unit technical cost for offshore gas fields under the base case scenario. Y-axis shows the cost of injection per tonne of CO2. The x-axis shows the amount of CO2 injected in Mtonne/yr.

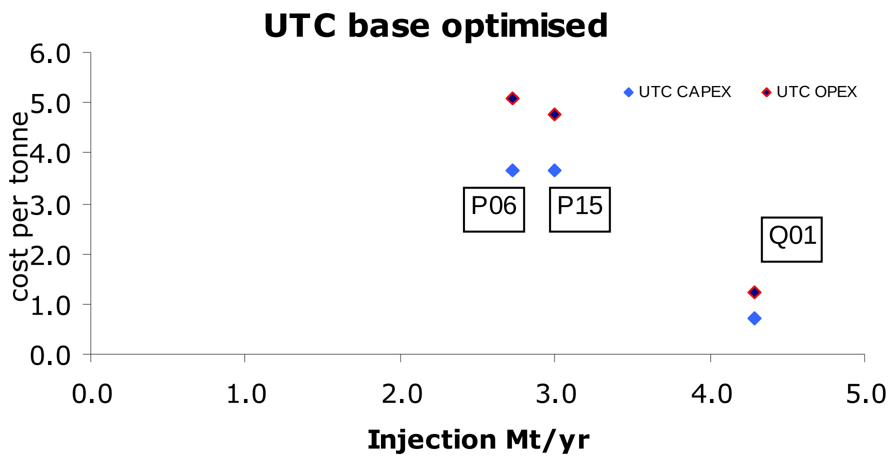

Figure 12 Unit technical cost for offshore gas fields under the optimized base case scenario (exclude small fields and reduce injection locations) Y-axis shows the cost of injection per tonne of CO2. The x-axis shows the amount of CO2 injected in Mtonne/yr.

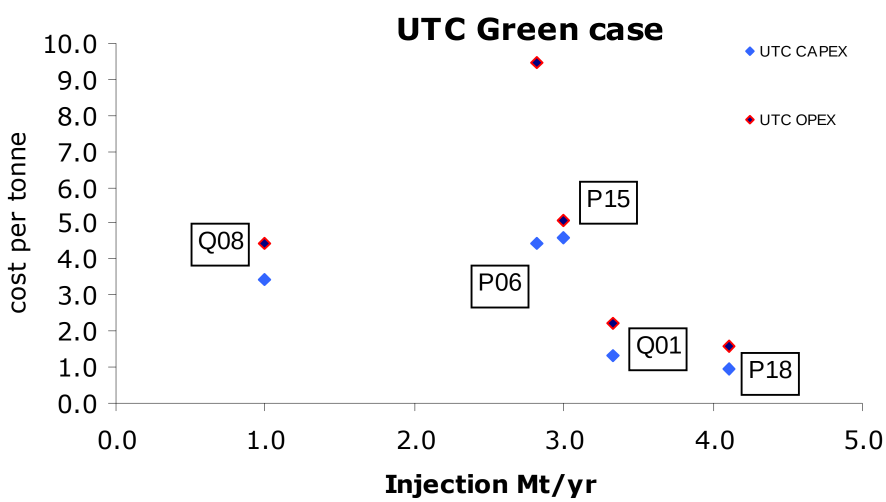

Figure 13 Unit technical cost for offshore gas fields under the Green case scenario. Y-axis shows the cost of injection per tonne of CO2. The x-axis shows the amount of CO2 injected in Mtonne/yr.

In Figure 14, we show the relationship between the amount of CO_2 stored and the UTC per reservoir in the K and L blocks. We can conclude that Figure 14 does not provide conclusive insights on economies of scale for the thirteen offshore storage reservoirs in the K12-L10 cluster. The figure does however show an overall trend of low UTC for reservoirs with high storage capacities.

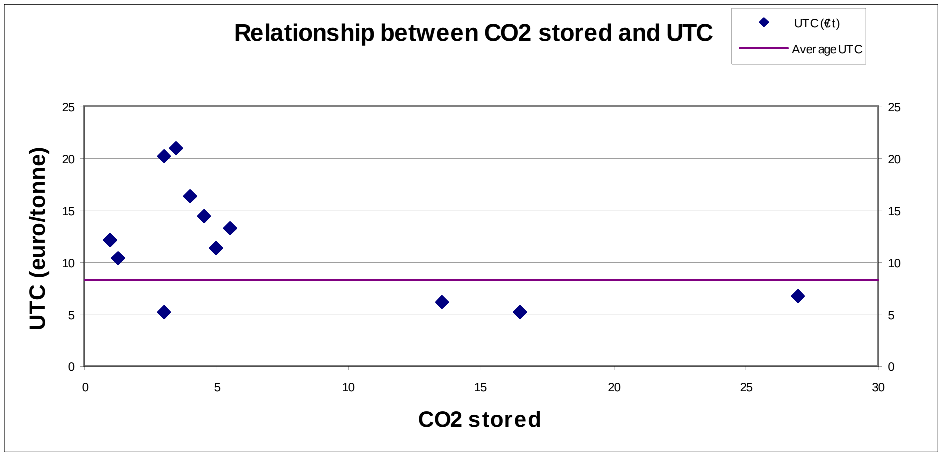

Figure 14. Relationship between amount of CO_2 stored and UTC for reservoirs in the K12-L10 cluster. Average UTC for the shown reservoirs/clusters is also indicated as a purple reference line. Typically, larger reservoirs have UTC below the overall average for these blocks

In Table 13, we show the offshore storage cost for the scenarios which only include the P and Q blocks. The total cost including CAPEX and OPEX for these blocks range between 1 and 2.5 €/tonne CO_2. Storage cost per tonne show higher shares for the OPEX (60%) compared to the share of CAPEX (40%).

In the EBN/Gasunie report it is reported that economies of scale are present for the K and L blocks. Overall, offshore storage costs thus most likely depend strongly on storage capacity but also on the location and case specific technical requirements per reservoir.

Table 13. Offshore storage cost in P and Q blocks in total cost and €/tonne

	Total cost in M€			UTC €/tonne		
Scenario	CAPEX	OPEX	Total	CAPEX	OPEX	Total
green case	502	691	1193	1.06	1.46	2.52
Base case	489	772	1261	0.51	0.81	1.32
Base case optimized	373	534	907	0.39	0.56	0.95

UTC CAPEX is calculated as total cost divided by total CO_2 stored. UTC OPEX is calculated as total OPEX divided by total CO_2 stored.

4.4 Summary of reviewed results

EBN/Gasunie has used scenarios to estimate the transport and storage cost of CO_2 in WNL (predominantly offshore) and NNL (onshore). With the use of these scenarios we calculated the UTC for CO_2 transport and storage. Total UTC is about 10-11 €/tonne for onshore transport and ranges between 6 and 14 €/tonne for offshore transport. Costs for onshore transport are probably estimated too high due to the low (and most likely not cost-optimal) transport pressure. Based on the assumptions and information in the EBN/Gasunie report it is not possible to update the cost function of the evaluation tool based on the provided cost data related to CO_2 flow, pressure and transport distance.

The average UTC for onshore storage is estimated between 2 and 4 €/tonne CO_2. The results for offshore storage scenarios show that average UTC (including OPEX and CAPEX) range between

2 and 14 €/tonne CO_2. UTC for offshore storage reservoirs in clusters not taken into account in the Base and Green scenarios are however estimated to range between 1 and 21 €/tonne.

Economies of scale for both on- and offshore storage could not be accurately determined based on the results in the EBN/Gasunie report. It is however likely, given the assumptions they use, that some economies of scale are expected for storage, especially for offshore storage. Storage costs are however expected to vary considerably depending on reservoir specific technical (and economical) requirements. Other important factors include the timing of injection in terms of the starting date of injection and the duration of injection. These factors are probably more cost dominant than the capacity of the reservoir.

Without more insights into the detailed assumptions used for both CO_2 transport and storage cost calculations it is not possible to reproduce the EBN/Gasunie results. Without further information it is therefore not possible to update the cost functions in the evaluation tool. It is therefore recommended to discuss the main assumptions of EBN/Gasunie and consult them before updating the evaluation tool.

Next steps to be included in this discussion (and eventually the evaluation tool) are:

- Assumptions on transported flow, distance and pressure
- Different assumptions regarding calculation of onshore and offshore transport cost
- Assumptions on non-energy OPEX cost for compression
- Assumptions on number of wells and other infrastructural requirements per reservoir
- Assumptions on injection debit and pressure
- Infrastructural requirements for both transport and storage over time as scenario evolves and more CO_2 is to be injected and transported.

5 NNL storage capacity

In order to model the development of CCS in NNL, data on storage capacity, injection rates and locations are needed, as well as the year of expected end of production. A database of CO_2 storage options was collected in the framework of the CATO-1 project (Kramers et al., 2007). The database is based on publicly available data, derived from production plans and well data.

Storage capacity for CO_2 in a depleted gas field is derived from an estimate of the ultimate recovery (total amount of natural gas produced), with the assumption that the pressure in the field can be brought back to its initial state. As the ultimate recovery is generally confidential, the storage capacity was estimated from field area, average thickness, porosity and depletion level.

This database was reviewed in this project, to include any recent updates of gas field production plans published by operators. The database now contains data of all onshore and offshore gas fields. Updates are mainly found in the expected end year of production. End year of production tend to shift backwards with increasing gas prices.

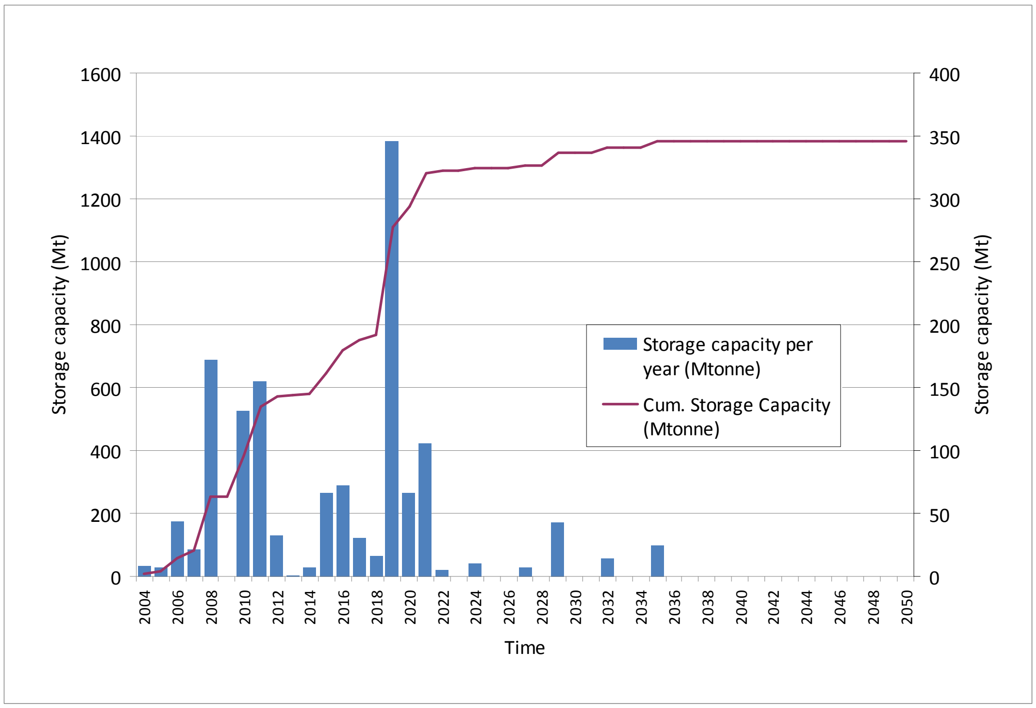

Figure 15. Availability of storage capacity from 2004 onward. The bar graph gives the storage capacity coming available (right axis); the purple curve shows the cumulative storage capacity (left axis).

Figure 15 shows cumulative CO_2 storage capacity for the gas fields in NNL, for the period 2010 onwards. This figure is a combination of the CO_2 storage capacity and expected end years of production. Abandoned fields and fields that are being used for gas storage are not included. The total cumulative storage capacity in the NNL fields is of the order of 1.4 $GtCO_2$. The EBN-Gasunie study reports a total storage capacity of about 850 Mt. The region considered in this report is slightly larger than the one in the EBN-Gasunie report, including also fields in the southern part of Drente.

The availability of the gas fields is shown in Figure 16. Many smaller and larger fields are already close to or even past their expected end of production. The EBN-Gasunie report identified a number of fields for the first phase of CO_2 storage. If larger volumes of captured CO_2 are produced after 2020 (after the demonstration phase), there will be many empty fields to choose from. Available fields are to be ranked, on economical, geological and social grounds.

Figure 17 shows the cumulative storage rate (in Mt/yr) for all available depleted gas fields for the same period. This graph was derived with the assumption of a well injection rate of 1.5 Mt/yr and up to three active injection wells per field. Some fields have (many) more wells, either active (producing) or closed in, but many fields have three wells or less. Using three wells results in a (maximum) injection rate of 4.5 Mt/yr for each field. While this may be underestimating feasible injection rates for larger fields, for smaller fields. This approach results in an average injection time of about 8 years for NNL fields. The well injection rate depends on reservoir thickness, permeability and other parameters (such as well completion, the use of additional pumps), which are generally not available for each well or field. The value of 1.5 Mt/yr is a reasonable average injection rate.

It is to be noted that the underlying assumption in deriving this figure is that CO_2 injection projects use existing wells only and that no new wells are drilled. If the need for higher injection rates arises and the development of a new depleted gas field for storage is not an option, an additional, new well may be constructed to increase injection rates.

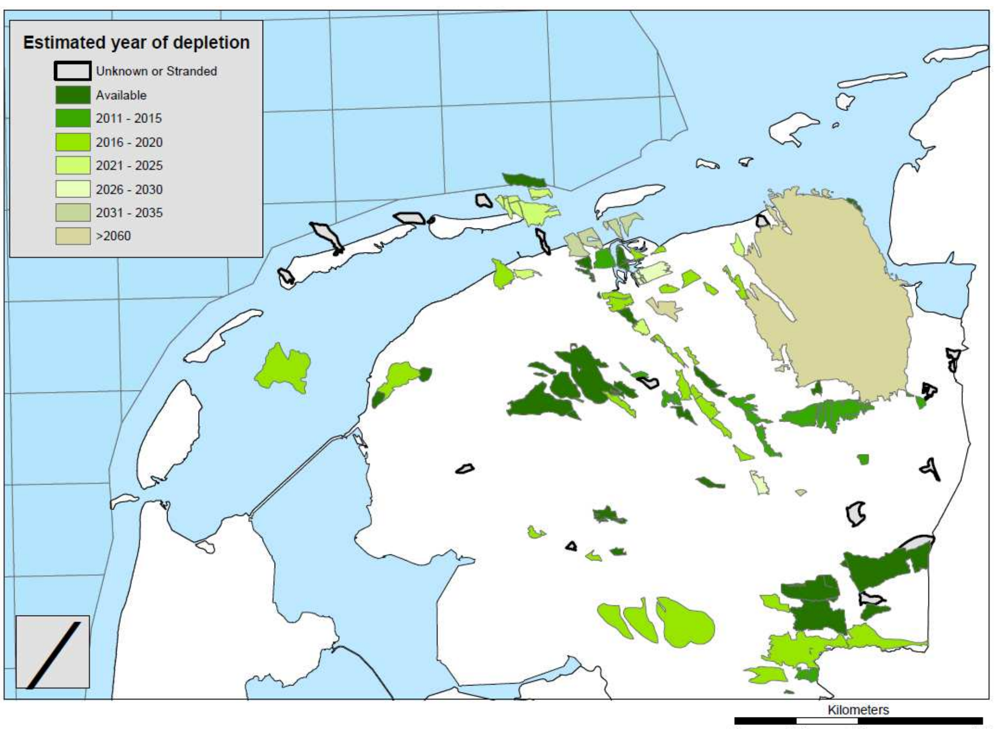

Figure 16. Gas fields in NNL, indexed by year of depletion (end of production). Open polygons represent stranded fields, or fields for which no data are publicly available.

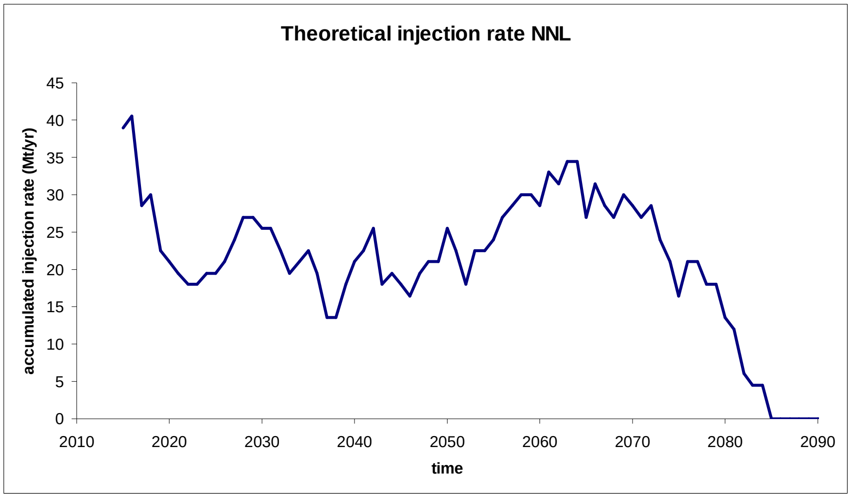

Figure 17. Injection rate capacity from 2010 onward. This was derived from an assumed injection rate of 1.5 Mt/yr/well and the number of currently active wells in each field. The rates were derived with the assumption of at most 3 active injection wells for each field, or less, if the field currently has less active wells.

The cumulative injection rates, shown in Figure 17, give a first-order estimate of the upper limit on the volumes that can be accommodated on a yearly basis in depleted gas fields in NNL. This rate, 20 – 30 Mt/yr, is well above the rates of capture as shown in Section 4.1. Similar results were obtained for offshore storage (Figure 18). With a similar total storage capacity of the order of 1 Gt, injection rates in offshore gas fields are also of the order of 40 Mt/yr, although the theoretical rates decay more quickly, due to the fact that the offshore fields are closer to the end of their lifetime than the onshore fields.

While the results suggest that with the capture scenarios as presented no problems are to be expected at the level of injection rates, these results can also be interpreted in terms of capacity available for CO_2 from other regions, either nationally or internationally. This could help develop CCS in NNL and decrease the cost of developing the necessary infrastructure.

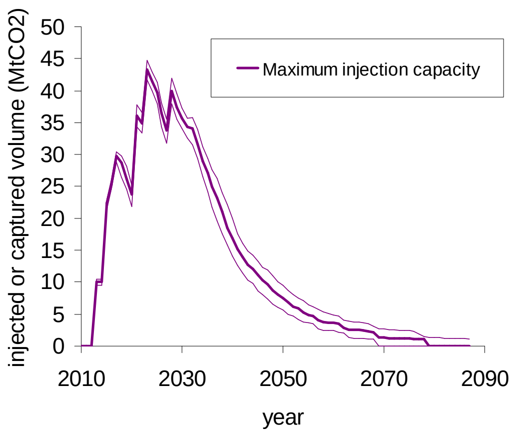

Figure 18. Injection rate capacity from 2010 onward, for offshore fields (taken from ref. [3]).

The analysis in Figure 17 does not include the distribution of the fields over NNL or the connections to the central trunk line grid. Figure 19 shows the current natural gas trunk line infrastructure. It can be expected that the main pipelines will still be used for the transport of natural gas long after the last gas field in the Netherlands is depleted. New CO_2 transport lines will need to be constructed, which will most likely follow the current transport corridors. The smaller satellite pipelines connecting the gas fields to the trunk lines may be amenable to CO_2 transport

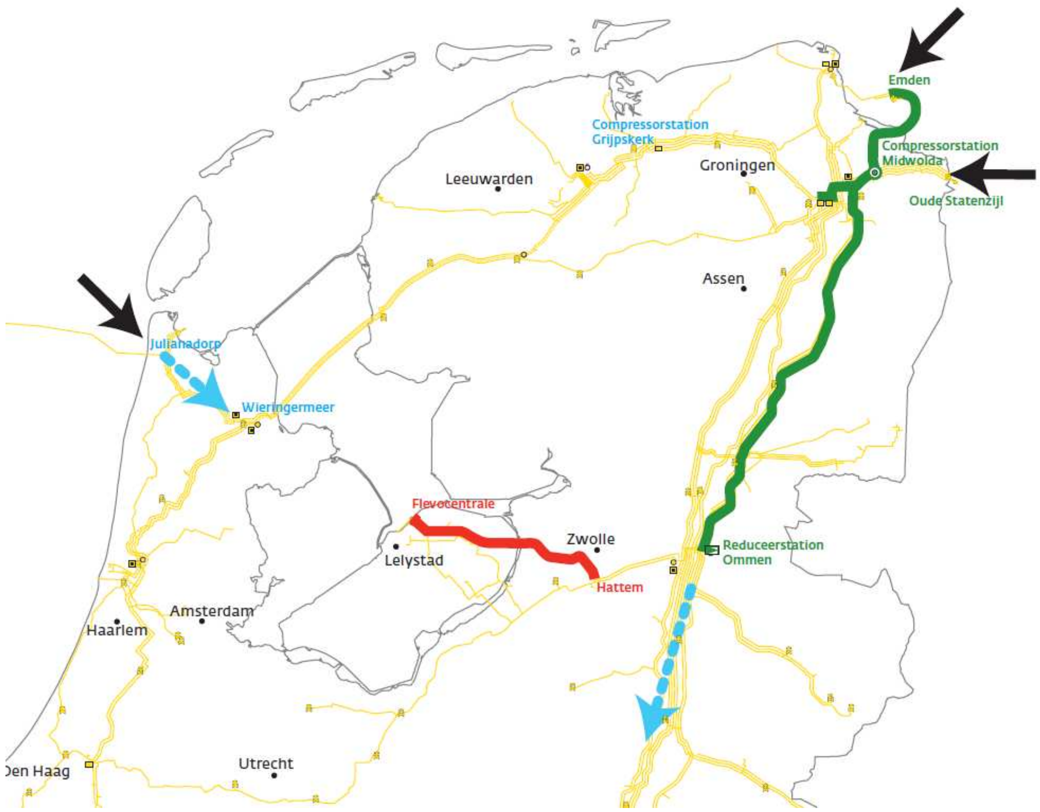

Figure 19. Current infrastructure (only the trunk lines are shown) that connects the gas fields in NNL (image taken from www.nlog.nl). Future CO_2 pipelines are expected to follow the natural gas pipeline corridors. Arrows indicate locations where additional gas transport capacity will be installed.

6 Further modelling of CCS development in NNL

The information contained in the EBN/Gasunie study is relevant for a subsequent, more detailed modelling of long-term CCS in NNL. The cost data in the report for offshore CCS activities is based on a recent report on offshore CCS cost [13], while Gasunie provided input for onshore transport.

The conclusion of the review of the EBN/Gasunie study is that the report does not directly allow a replication of the results with the information presented in the report. Important assumptions should be discussed with EB/Gasunie to understand the details behind the assumptions so that we can update the evaluation tool.

Some cost overviews are however directly available for on- and offshore storage facilities. For example, basic relationships between the number of wells and storage cost can be derived with the information in this study.

Important information that should be included in the evaluation tool is missing on the following aspects:

- Transport pipeline (trunkline) pressure and diameters;
- Transport distances and cost;
- Energy cost of compression;
- Storage capacity and storage rate at field level in NNL.

There is sufficient information in the report to derive relationships between:

- Number of wells and CAPEX & OPEX;
- Difference between onshore and offshore storage cost.

Based on the sections above we have defined the requirements for a CCS network modelling tool to extend the results in the EBN/Gasunie report. We have done this for transport and storage, both on-and offshore.

Transport
In order to make accurate calculations for the cost of transport we need:

- to determine pipeline CAPEX cost for the annual CO_2 flow between sources and sinks. A formula should include at least:
  - transport pressure (and pressure drop)
  - pipeline diameter
  - CO_2 flow
  - length of the pipeline
  - A distinction between offshore and onshore pipelines.
- A representative value for annual transport OPEX cost, excluding compression. We can derive this figure directly from the data presented in the EBN/Gasunie report.
- Formula for calculation of compression cost (CAPEX and OPEX) based on:
  - Required compression ratio (pressure out/ pressure in)
  - Energy cost
  - Cost of compressor (depending on size of the compressor)
  - We need to distinguish between energy related cost for compression (OPEX) versus non-energy related OPEX. This is not possible based on the data in the EBN/Gasunie report.

Storage

In order to make accurate calculations for the cost of storage we need:

- A figure for the amount of CO_2 annually injected per well, or well capacity. One estimate could be derived for the P18 cluster, which has an injection of 0.7 Mt /well/yr. A
- We need a figure for the amount of wells per reservoir and/or per cluster. In this report, it is assumed that up to three injection wells can be used in each field. A more field specific approach is needed.
- We need a figure for the total storage capacity per field in NNL. Data based on publicly available data are presented, which agree on an aggregated level, but capacities should be based on the total produced volume of gas.
- We use the CAPEX and OPEX for both on- and offshore storage facilities. The relationship between the number of wells and OPEX and CAPEX is clearly reported in the EBN/Gasunie report.
- We need to define a relationship between the amount of wells per reservoir and the (maximum) injection capacity per well, as well as how this varies with time. We can then determine the cost-optimal amount of wells per reservoir.

The tool that is envisioned for the extension of the EBN/Gasunie study was developed in the framework of an EU-funded project [14] and was used previously for the Netherlands offshore [3]. The tool computes the feasibility of CCS, taking into account limits arising from the geological side (storage).

The tool contains modules that describe the major elements of the CCS chain: capture, compression, transport and storage. It can handle multiple sources and multiple sinks, connected through a network of pipeline or ship connections. Uncertainties in data are handled stochastically to produce a realistic estimate of the uncertainty in the key performance indicators that the tool produces. These include physical as well as economical parameters: examples include volumes of CO_2 transported and stored, start dates of storage and of transport connections in the network, and cost estimates of (elements of) the CCS chain.

This tool is ready for deployment and application to NNL, using the cost data presented in the EBN/Gasunie report and with the remaining elements to be defined as explained above.

7 Conclusion

The analysis of the currently available data and results of development of CCS in NNL presented above, shows which elements should be included in a model. Together, these should cover the complete CCS chain, with the most important links between elements of the chain.

The recent study of CCS feasibility in the Netherlands shows that relevant elements of the modelling are the following:

- forecast of captured volumes from 2015 onwards. These volumes are shown in Figure 1.
- forecast of available storage capacity from 2015 onwards. Section 5 shows the data in the CATO2 (updated CATO1) database.
- analysis of options for reuse of existing infrastructure. Re-use can decrease the cost of CO_2 storage, which is important especially for offshore activities; recent studies have investigated this option (NOGEPA studies). For NNL, the infrastructure for which re-use is an option are the field installations, including wells, and satellite pipelines connecting the fields to the main gas transport infrastructure.

In addition to these data, cost estimates for onshore CCS activities are required. These include storage, transport, compression and capture. The analysis shown in Section 4 shows that some of these cost elements are available. The full details behind the assumptions on cost elements could be derived after detailed discussion with EBN and Gasunie.

Finally, extending the EBN/Gasunie planning for NNL to a longer term can be performed with the CCS modelling tool that has recently been applied to the Netherlands offshore. An update of the cost modules in this tool is required. At this moment, no extensive changes or additions to the tool are foreseen.

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