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Opportunities and challenges for CarbFix: An evaluation of capacities and costs for the pilot scale mineralization sequestration project at Hellisheidi, Iceland and beyond

Elisabet Ragnheidardottir[a,*], Hólmfridur Sigurdardottir[b,**], Helga Kristjansdottir[c], William Harvey[d]

[a] Reykjavik Energy Graduate School of Sustainable Systems, Iceland
[b] Reykjavik Energy, Iceland
[c] Faculty of Economics, University of Iceland, Iceland
[d] School of Science and Engineering, Reykjavik University, Iceland

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ABSTRACT

Reykjavik Energy, in cooperation with four academic institutions, is testing carbon capture and storage (CCS) through mineral carbonation at the Hellisheidi geothermal power plant. The goal of the work, launched in 2007, is to test *in situ* sequestration of CO_2 and mimic the natural carbon mineralization process that contributes to the global carbon cycle. The Hellisheidi site provides both a suitable basalt storage site as well as a stream of nearly pure CO_2 from a parallel pilot project. This paper, drawing from earlier research, aims to re-evaluate the costs associated to the CarbFix method for this specific site. The pilot program, along with its known costs and operations, is scaled to higher flow rates of CO_2. The findings indicate that at low CO_2 flow rates the project is heavily weighted in capital costs while higher CO_2 flow rates are subject to the variable costs such as electricity and water. In light of this, research should continue to assess the water and energy requirements for the system. The CarbFix technology employed elsewhere would undoubtedly encounter large CO_2 point sources and will then be sensitive to these variable costs. The profitability assessment, over a 30-year life, shows for the higher flow rates, adequate returns on investment under the existing trading prices.

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1. Introduction

A pilot study in southwest Iceland is testing carbon capture and storage (CCS) through mineral carbonation. Mineral carbonation is the fixation of CO_2 as a stable mineral, using replication of natural weathering processes in an imitation of nature (Oelkers and Cole, 2008). The study, launched in September 29th, 2007, is a cooperation between Reykjavik Energy, Institute of Earth Sciences of the University of Iceland, Earth Institute – Lamont-Doherty Earth Observatory of Columbia University in New York and the Centre National de la Recherche Scientifique in Toulouse, France. The majority of the work takes place at the Hellisheidi geothermal power plant. The goal is to test the *in situ* sequestration of CO_2 through mineral carbonation in basalt. The project consists of field scale injection of water-saturated CO_2 into basalt, laboratory experiments, and geochemical modelling (Sigurdardottir, 2009a,b).

Carbon mineralization is a key process of the global carbon cycle in which atmospheric CO_2 is stored (Berner et al., 1983). The resulting carbonate minerals are stable and provide environmentally low risk storage over geological time scales (Gislason et al., 2010). As basalt is heavy in divalent cations, a vital requirement for carbon mineralization, and low in silica, it provides an ideal environment to inject CO_2 for the purpose of storage (McGrail et al., 2006).

1.1. CarbFix

The CarbFix injection site is approximately 3 km south of the Hellisheidi power plant. The Hellisheidi geothermal power plant currently has a capacity of 213 MW_e but is due to be extended to 303 MW_e (Reykjavik Energy, 2009). It emits 60,000 tonnes of CO_2 (tCO_2) per year (Gislason et al., 2010), rising to 90,000 tCO_2 with future increases in electrical production. Non-condensable gases present in the produced geofluid result in CO_2 emissions, as well as hydrogen sulphide (H_2S), hydrogen (H_2), nitrogen (N_2), methane (CH_4) and oxygen (O_2) (Gislason et al., 2010). The non-condensable gases are mainly CO_2, around 83% by mass, with H_2S around 16% and the remaining elements combined around 1% (Matter et al., 2008).

* Corresponding author at: Købmagergade 20, 2 Floor, 7000 Fredericia, Denmark. Tel.: +45 6039 6069.
** Corresponding author.
E-mail addresses: elisabetvilborg.ragnheidardottir@vattenfall.com (E. Ragnheidardottir), holmfridur.sigurdardottir@or.is (H. Sigurdardottir).

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In order to begin the mineralization process CO_2 saturated water, or dissolved carbonic acid (H_2CO_3), that promotes carbonation, must be injected for the purpose of liberating cations (Matter and Kelemen, 2009; Gislason et al., 2010). This begins with the transport of CO_2 at 25 bar from an H_2S abatement system and separately the transport of water pumped from well HN-1. The water flow in the pilot project uses 27 l/s for each kg/s of CO_2 to be injected (Gislason et al., 2010). This is in accordance with the water requirement for H_2O at 25 °C. However, as noted in the 2010 paper by Gislason et al., the theoretical requirement for the water from HN-1, at 19 °C, is 22 l/s. As the water temperature decreases the solubility of CO_2 increases requiring less water. The pilot project will inject at the rate of 27 l/s in order to verify the stability of the temperature of the injection water. This will also help to identify the rate at which gas bubbles dissolve during descent (S. Gislason, personal communication, November 12, 2010).

Once at the injection well, HN-2, the two are injected separately until a depth of 350 m where the pressure reaches 25 bar, as the water level is 100 m (Gislason et al., 2010). The CO_2 will be fully dissolved in the water while it is descending in the injection well, resulting in a single fluid phase entering the storage formation. To accomplish complete dissolution a new injection system has been developed and installed in the injection well. The water and CO_2 will be mixed at a designated point in the borehole. The water stream will carry CO_2 bubbles down-well to more than 500 m depth where the hydrostatic pressure will ensure complete dissolution of the CO_2 before entering the aquifer (Gislason et al., 2010). At a depth of 500 m and where the water level is 100 m, the pressure should be approximately 40 bar. This method requires no additional compression of the CO_2 and gravity provides the required water pressure. The pressure in the storage reservoir is approximated to be 5 MPa (Aradottir et al., 2009) and the temperature between 30 and 55 °C (Gislason et al., 2010).

Fig. 1 shows the layout of the wells HN-2 (injection well) and HN-1 (water sources), as well as the monitoring wells. Multiple monitoring wells in conjunction with both water and CO_2 tracers allow for deep reservoir and shallow aquifer monitoring (Matter et al., 2008). The deep monitoring wells are HN-4, HK-34, HK-31 and HK-26 and the shallow monitoring wells are HK-12, HK-25, HK-7 and HK-13. The injection well has a depth of 2000 m and the monitoring wells are between 100 and 1400 m (Gislason et al., 2010).

The flow of CO_2 used by the CarbFix project is a result of a parallel project underway to reduce the H_2S emissions from the Hellisheidi plant. Reducing emissions will be accomplished by separating the H_2S from the geothermal gas and re-injecting it into the geothermal reservoir with the brine (Reykjavik Energy, 2008). This program, like CarbFix, is in a pilot phase. After this process the residual gas stream from the H_2S abatement system is relatively pure CO_2.

The area for injection is estimated to be 3 km long, 1500 m wide and 600 m thick (Aradottir et al., 2009). The estimated mass that the area could store is 12 mega tonnes (Mt) of CO_2 (Gislason et al., 2010). The formation potentially could provide storage for 200 years at the current Hellisheidi annual emission rate of 60,000 tCO_2.

1.2. Previous research

Much of the work to date on carbon mineralization as a method of CCS has focused on the geophysical properties and reactions, but limited work has been performed on the costs associated to the process itself. Part of the pilot study is to include a review of the associated costs and to provide insight into cost drivers. In 2010 this study was completed with a review of three scenarios including the pilot program itself and two scaled versions signifying increased flow rates of CO_2 (Ragnheidardottir, 2010). The two scaled scenarios were based on, firstly, full CO_2 sequestration from the Hellisheidi geothermal power plant, 60,000 tonnes per year, and, secondly, a hypothetical coal based power plant with emissions over 1 million tonnes per year (Ragnheidardottir, 2010). This paper reviews the first two scenarios again while a new scenario is added to replace the original third, or the coal based scenario. The new scenario represents one that is more comparable to the original two scenarios so that the real relationship between costs and CO_2 flow rates at the Hellisheidi storage reservoir can be assessed.

As the H_2S abatement system is a separate project from CarbFix, and would be pursued regardless of the existence of CarbFix, the abatement costs are not included in the previous research or this analysis. The costs incorporated are thus the transport and storage aspects of CO_2 through the CarbFix technique and not the capture costs, as the H_2S abatement system includes this. Although CarbFix does not include the costs of capture the research provides significant information, as the act of capturing CO_2 by the emitter can be an independent project from that of transporting and injecting (Ragnheidardottir, 2010). Currently much research has focused on the economics of designing capture ready plants (Bohm et al., 2007). By designing the plant to be capture-ready the operator can ensure higher efficiency and less CO_2 production per unit of energy output. This in turn will reduce the energy penalty to the plant after capture and decrease the costs associated with capture, which is the highest contributor to CCS costs (IPCC, 2005). Once research realizes methods to decrease the capture costs, more focus will be on assessing storage methods and options in the vicinity that are the most competitive.

2. Methodology

2.1. Cost analysis

The goal of the research is to determine the cost per tonne in Euro (€) of CO_2 stored[1] through carbon mineralization in the CarbFix pilot program (CPP). Two references of cost are used in the CarbFix scenario; experienced costs through the pilot program and referenced costs in literature. Using this cost analysis information, greater CO_2 sequestration scenarios are studied offering insight into the changes in predominant cost factors as CO_2 flow increases.

Scenario 1: Pilot program (CPP) with CO_2 flow rate of 0.07 kg/s.
Scenario 2: Hellisheidi full-scale (HFS) case, with CO_2 flow rate 1.8 kg/s.
Scenario 3: Maximum Reservoir Exploitation (MRE), with CO_2 flow rate 12.7 kg/s.

The CPP scenario serves as a baseline scenario in which the relatively known costs, through current project operations, can be scaled according to changes in variable factors. The CO_2 flow rate is 0.07 kg/s and the total captured emissions are 2100 tCO_2 annually. The second scenario, HFS, utilizes the full emissions from the Hellisheidi power plant or 60,000 tonnes CO_2 per year, or 57,000 tonnes after capture. The third scenario, MRE, has captured emissions of 400,000 tonnes CO_2 per year. This flow rate was calculated by limiting the exploitation of the reservoir to at least 30 years. That is that each scenario must limit its injection per year so that injection can continue for 30 years in order for comparison of costs.

Each scenario assumes the use of the same reservoir at the Hellisheidi injection site. The aim of the paper is to assess the

[1] As some of the costs were given in varying currencies the following exchange rates were used according to the 2009 averages from January to June: ISK/US$ = 124; EUR/US$ = 0.74; ISK/EUR = 166.

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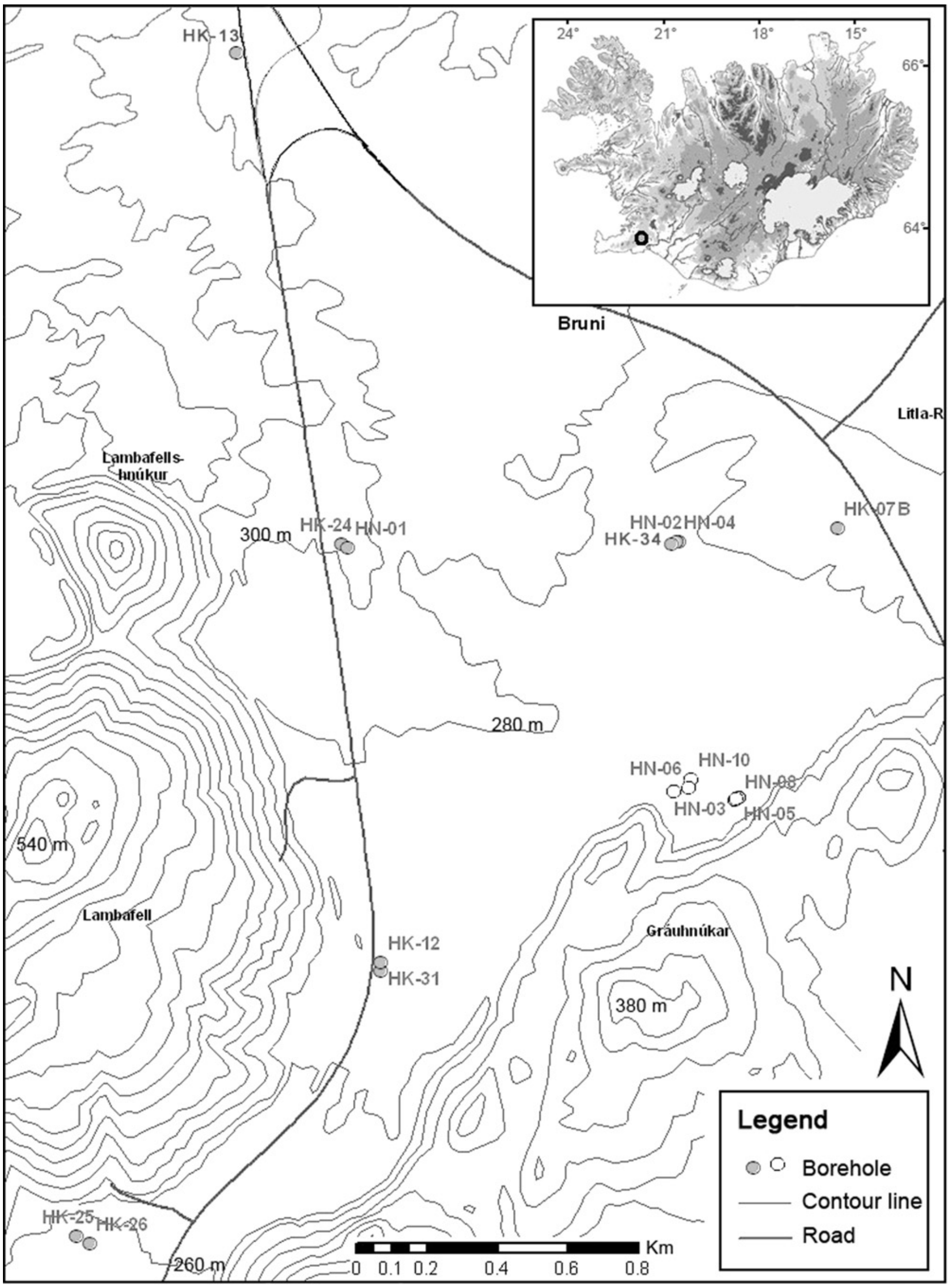

Fig. 1. N-S geological cross-section of the injection site, including injection well (HN-2) and monitoring wells (Alfredsson et al., 2008).

cost dynamics of this particular program in its research phase. An alternative could have been to compare scaled up scenarios at other sites where basalt carbon mineralization is possible, such as the Columbia River Basalts Group in the United States or the Deccan basalts in India. However, different reservoirs, as well as countries, offer different attributes that may not compare, such as reservoir temperature and pressure at the injection depth, faster or slower ground water flows, or availability of a water resource.

The emissions captured are slightly lower than those emissions that would be emitted from the source point. This is because every capture system has an efficiency ratio of the CO_2 emitted and CO_2 actually captured due to leakage. In the H_2S pilot abatement system the capture efficiency is estimated to be 95%. As the abatement system is still under development this may result in a higher or lower figure in the future.

A majority of the capital costs observed through execution of the pilot program are the basis for the scaled scenarios. This includes equipment, installation, design and cost for wells: both injection and monitoring. In addition to these known costs the scaled up scenarios include licensing and permit costs and site screening. The site screening cost is present in all the scenarios and is based on work by Smith et al. (2001); converted to Euros and adjusted for inflation. As the same reservoir is being used for all three scenarios the site screening cost is kept constant. The licensing and permit costs are estimates provided by the environmental engineering department of Reykjavik Energy and should be indicative of the relative cost of for regulatory requirements by Directive 85/337/EEC for an Environmental Impact Assessment.

Equipment for all scenarios includes pumps, compressors, valves, piping and instrumentation. The costs for the equipment,

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as well as the design and installation, are scaled using the pilot project cost and the following formula:

$$\text{Scaling factor} = \left[\frac{\text{Flow}_{\text{scaled}}}{\text{Flow}_{\text{pilot}}}\right]^{0.6},$$

where the flow of CO_2 in the scaled scenario is divided by the pilot flow in kg/s and then the scaling exponent of 0.6 applied (Tester et al., 2005). Thus the scaling factor for the HFS scenario is 7 and for the MRE scenario 23.

The remaining capital costs are the injection wells and the monitoring wells. The monitoring wells serve to monitor the CO_2 leakage and other environmental impacts that the pilot study may produce (Ragnheidardottir, 2010). Directive 2009/31/EC on the geological storage of CO_2, while it addresses the framework for regulatory requirements of pre and post-closure monitoring, does not lay down non-site specific guidelines for monitoring (Directive 2009/31/EC). The commercial CCS projects to date have implemented monitoring practices that fit with the site being injected into as well as the verification goal of the project (Wartmann et al., 2009). The monitoring strategy and consequent cost was developed by all involved institutions for close research scrutiny of the pilot program (Sigurdardottir, 2009a,b).

The monitoring system employs the use of 9 monitoring wells as well as monitoring the power plant gases, direct measurements of CO_2 captured by injecting tracers, systematic collection and analysis of groundwater downstream, monitoring soil CO_2 flux and monitoring of atmospheric CO_2. It may be that for larger scale commercial solutions the monitoring costs will not scale with size and so for the purpose of the analysis it remains constant through the three scenarios. In future work a strategy for incremental additions of monitoring wells over project life may be considered. The cost per monitoring well, 0.32 million euros (M€), is representative of the average actual cost experienced by Reykjavik Energy for monitoring wells during this pilot phase (Ragnheidardottir, 2010).

A large portion of the capital costs is attributed to injection wells. The number of injection wells needed is dependent on three factors. The first is the amount of water flow the injection well is able to receive (injectivity). This is well documented from experience in the geothermal power field at Hellisheidi. The second is the rate at which the fluid, entering the bedrock, is transported away from the injection well. Should the fluid flow slowly from the injection well and react at a higher rate with the basalt, the risk is that the injection well and area surrounding it becomes clogged by carbonate scaling, reducing the injectivity. The third is the rate at which the fluid reacts with the basalt forming carbonates (Ragnheidardottir, 2010).

Determining the rate at which the fluid reacts with the basalt to produce carbonates is still under scientific study and is one of the objectives of parallel projects underway in conjunction with the pilot study. In the CPP case one injection well is being used based on actual operations in the project (Gislason et al., 2010). The scaled scenarios use the typical well injectivity at Hellisheidi, or 80–120 litres per second (l/s) (Ragnheidardottir, 2010). The number of injection wells is calculated using the amount of water being pumped in well HN-2 in l/s. The water flow rate is determined from the HN-1 water requirement presented by Gislason et al. (2010) or 40 l/s and 279 l/s for the HFS and MRE scenarios respectively. This requires for the HFS scenario one (1) well and three (3) wells for the MRE. The cost of each well is based on drilling costs experienced during the development of the Hellisheidi field and is 1.9M€ (Ragnheidardottir, 2010). The cost of monitoring wells is less both due to their smaller size in width and depth.

Annualization of the capital costs employs an interest rate of 4.6% with a 15-year pay back period. The interest rate is based on the Euro Interbank Offered Rate (EURIBOR) with an additional credit default spread (CDS) to represent a risk premium. This interest rate represents the absolute best rate that the current market offers (Ragnheidardottir, 2010).

Table 1
Three scenario assumptions compared; CarbFix pilot program (CPP), Hellisheidi full scale (HFS) and Maximum Reservoir Exploitation (MRE).

System assumptions	CPP	HFS	MRE
CO_2 emitted by source (tCO_2/year)	2200	60,000	421,000
CO_2 stored annually (tCO_2/year)	2099	57,000	400,000
Project time horizon (years)	30	30	30
Power requirement (kW_e)	200	830	3547
Water requirement (m l/year)	57	1254	8800
Increased flow from baseline	–	27	191
Scaling factor for capital costs	–	7	23
Scaling factor for fixed power	–	2	4
Injection well(s)	1	1	3
Monitoring wells	9	9	9

The variable costs incorporate energy, water and operations and maintenance (O&M). The annual O&M costs are 2.5% of the initial capital costs. The O&M factor is based on literature and the common factor used of 3% for capture and transport systems of CO_2 (Neele et al., 2009). However, as there is no capture included here and no booster stations required for transport, the system is less complicated and the annual O&M percentage is lowered to 2.5% of capital costs. The remaining costs, water and energy requirements, are CO_2 flow rate dependent. The costs are derived from the unit cost of water of 0.0001€/l[2] and the electricity cost of 0.036€/kWh.[3]

In the CPP scenario the energy requirement for the transportation and injection is approximately 200 kilowatts (kW_e) and is based on preliminary engineering designs[4] (Ragnheidardottir, 2010). This is split up between pumping, 15 kW_e and auxiliary systems, 185 kW_e. It is assumed that pumping energy requirements will scale linearly with flow rates and auxiliary system power consumption is fixed to a certain degree (Ragnheidardottir, 2010).

In order to appropriately scale the energy requirements in the HFS and MRE scenarios both the increase in CO_2 flow and the scaling formula is used. The energy requirement for the pumping is thus scaled times 27 for the HFS scenario and 191 times for the MRE scenario. The fixed power requirement, for the auxiliary services, does not scale with flow rate. The scaling formula is implied here but the coefficient is 0.25 and not the 0.6 that is used for scaling capital costs. The total energy requirement for each system is thus 830 kW_e (HFS) and 3.5 MW_e (MRE).

Table 1 presents the system assumptions presented in this chapter.

2.2. Profitability assessment

The profitability assessment takes into account relevant financial benefits available to the operator of this type of CCS system. It is assumed that the system would run for 30 years and that the capital required would be supplied by 30% equity and 70% by loans. In addition to the capital costs identified in the cost analysis, each scenario requires a working capital of on average 15% of the capital costs. Working capital is defined to be liquid asset balance to meet short and long term debts. The loan has a payable interest rate of

[2] This cost is found by referring to Reykjavik Energy's stated prices at http://www.or.is/Fyrirtaeki/Verdskraogskilmalar/Kaltvatn/ given in ISK and exchanged to Euros. Prices accessed May, 2009 and may have changed.

[3] This cost is found by referring to Reykjavik Energy's stated prices at http://www.or.is/Fyrirtaeki/Verdskraogskilmalar/Rafmagn/ given in ISK and exchanged to Euros. Prices accessed May 2009 and may have changed.

[4] Engineering designs for the pilot program are provided by Mannvit Engineering.

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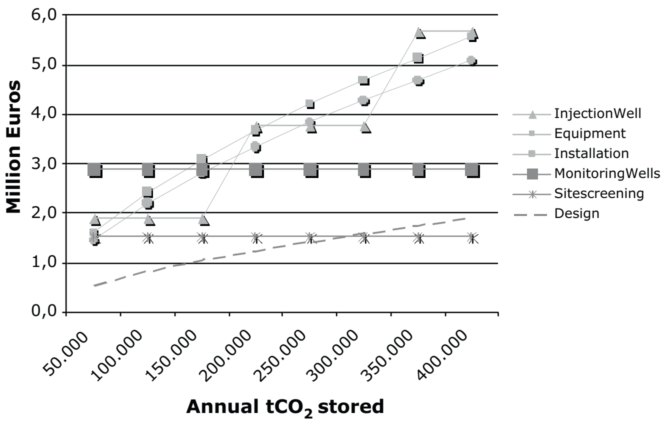

Fig. 2. Effects of increased storage on capital cost factors.

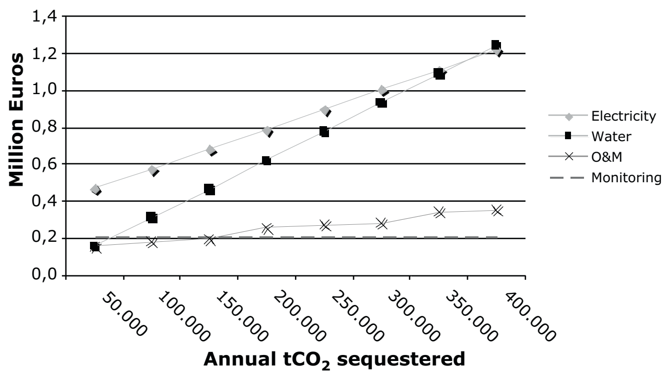

Fig. 3. Effects of increased storage on variable costs.

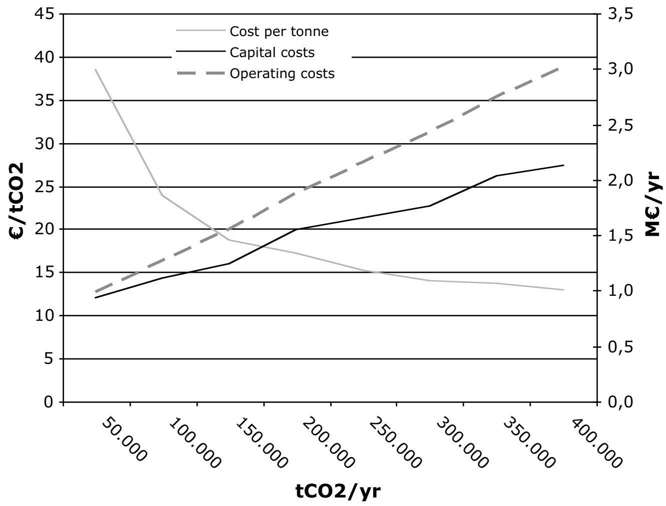

Fig. 4. Cost per tonne, capital and operating cost progression over increased CO_2 flow rates.

4.6% and is repaid in 15 years. The fixed and variable costs are based on the cost analysis already performed.

Assessing the three scenarios according to three financial return conditions provides the resulting price of CO_2 that would need to be available either through the market or as a tax. This first condition is the price of CO_2 today that would result in zero net present value (NPV). The NPV is a consideration of the future cash flows when the time value of money is taken into account. The discount rate used to calculate the NPV is 12% where the discount rate is the rate investors can earn on alternative investments.

The second requirement is the price of CO_2 that would result in a 15% internal rate of return (IRR). The IRR is the discount rate at which NPV is equal to zero. Investors can view the IRR as a key figure by which alternative investment opportunities can be compared. When the IRR is required to be 15% the price of CO_2 is required to be slightly higher. The third requirement is that the price of CO_2 be such that the IRR is 20%.

The price of emitting CO_2 is at an escalating scale of 5% per year from 2010. This represents the increase in severity on emissions prices needed when the ultimate goal is to stabilize atmospheric greenhouse gases (Wigley et al., 1996). As time progresses and climate change policy becomes stricter the price of emitting, whether purchased through a free market or a government tax, will become more expensive (Wigley et al., 1996).

3. Results

3.1. Cost analysis

The cost analysis draws from the assumptions and results in the original research by Ragnheidardottir (2010) though there are changes in comparative parameters, such as scaling of flow of CO_2. These changes aim to make the results not only more comparative but also site specific. The result of the cost analysis for the three scenarios results in a CO_2 storage cost ranging from 12.5 to 502.7€/tCO_2 with the CPP having the highest value. The main contributing factors to the large cost in the CPP scenario is the small amount of CO_2 that is being sequestered, 2100 tonnes annually, as well as to the high cost for monitoring wells and annual monitoring for the small pilot program. As the CO_2 flow increases, specifically when the annual CO_2 flow is more than 150,000 tonnes, the bulk of the capital costs are equipment, injection wells and installation. At lower CO_2 flow rates, as in the pilot program, the monitoring wells contribute largely to the high cost. This is characterized in Fig. 2. This is due to the fact that these three factors are both costly as well as scale with the flow of the CO_2. Monitoring wells become less significant portions of the capital cost, as their cost is held constant.

Fig. 3 shows the change in the individual operational costs as the CO_2 flow rate increases. When the rate of storage is 50,000–400,000 tonnes of CO_2 per year the electricity costs are higher but after 400,000 tonnes this changes. That is attributed to the fact that while a portion of the electricity costs is fixed, in the auxiliary system, the water costs scale purely with CO_2 flow rate.

The annualized capital costs also decrease in proportion of the annual costs as the CO_2 flow increases. In the CPP case the contribution by annualized capital costs to the total yearly cost is 61% but in the MRE scenario the percentage decreases to 43%. Fig. 4 shows the combined operational costs as well as the annualized capital costs and how the contribution changes over increased CO_2 flow rates. The primary axis shows how these changes affect the cost per tonne CO_2.

Table 2 summarizes the costs for each scenario, both in capital costs and annual costs.

While it may be useful to compare the costs presented in the pilot program and scaled to the larger scenarios, this can be difficult due to the nature of the separation of systems. Specifically, the CarbFix project does not include compression and this cost is generally included in other storage cost reviews. In general, costs for transport and storage in the literature should be higher than those of CarbFix due to this inclusion. Burton and Bryant (2009) characterize a 500 MW_e coal plant with 10,000 tonnes CO_2 emissions per day as having a capital cost for compression and installation

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Table 2
Cost analysis method results for all three scenarios.

	CPP	HFS	MRE
Capital costs (M€)			
Equipment	0.24	1.73	5.56
Injection well	1.89	1.89	5.67
Monitoring wells	2.88	2.88	2.88
Site screening	1.52	1.52	1.52
Installation	0.22	1.58	5.08
Design	0.21	0.59	1.90
Permits and licensing	0.00	0.06	0.06
Operations costs (M€)			
Electricity	0.06	0.20	1.07
Water	0.01	0.18	1.25
Monitoring	0.21	0.21	0.21
O&M	0.13	0.16	0.35
Working capital	0.18	1.31	4.20
Capital costs – annualized	0.65	0.96	2.12
Annual	1.24	3.01	9.20
€/tonne captured	588.54	52.83	23.00

equipment of 101–158 million euros.[5] In order to compare this cost, the CarbFix cost model is adjusted for the same CO_2 storage rate, or 3.6 million tonnes per year.[6] The CarbFix costs stand at less, at 88 million euros, but this is largely due to two factors. The first is that Burton and Bryant (2009) require 100 wells for extraction of brine and the reinjection after surface mixing. The CarbFix model does not assume costs for the extraction well HN-1, as Reykjavik Energy provides it to the project. Since the cost per well is available from Burton and Bryant (2009) the cost for surface mixing can be adjusted to exclude these. The cost per well is 0.56M€ and the number of extraction wells are 50, reducing the capital costs to a range of 46–103M€.

The second factor for the difference in cost is that Burton and Bryant (2009) consider compression in their equipment capital costs for surface mixing. There are also other differences in the cost basis in that the cost per well for CarbFix is 1.9M€ while the comparison paper considered here has a cost of 0.56M€ per well.

3.2. Profitability assessment

3.2.1. CPP scenario

The cost of CO_2 stored in the CPP scenario is found to be 502.7€/tCO_2 (Ragnheidardottir, 2010), however this is only a glimpse at one particular time of the system. In the profitability assessment the cost per tonne is calculated based on annual costs as they progress. Specifically Fig. 5 shows the effect that the decrease in loan expenditures has on the cost per tonne stored. The cost per tonne is calculated and includes the variables costs (water, electricity, monitoring and O&M) as well as the loan repayments and the depreciations. The variable costs are inflated at 1% per year from 2010. There is a large drop in the year 2025 when the loan is fully repaid.

The CPP scenario is excluded from the profitability assessment in practical terms as the cost per tCO_2 stored is 33 times higher than the current fluctuating price of 15€/tCO_2.[7] Even the current taxing system in certain European countries only reaches a price of 50€/tCO_2 (Baranzini et al., 2000). However, it is found that the

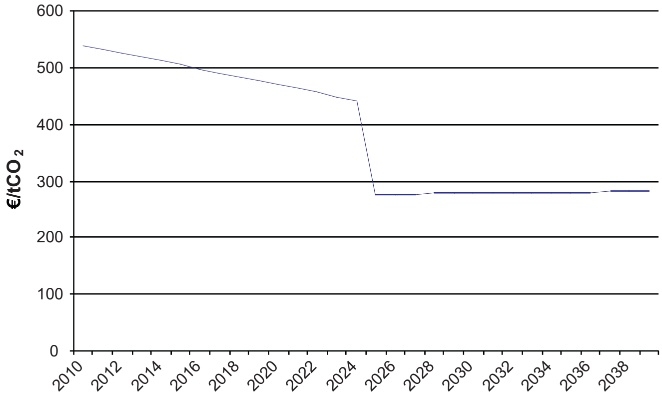

Fig. 5. CPP cost per tonne CO_2 stored over the life of the project.

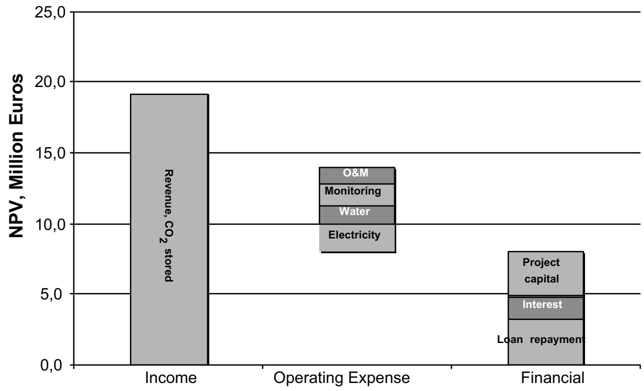

Fig. 6. HFS scenario at 31€/tCO_2 price with itemized contribution to the net NPV of 5.2M€.

price at which the NPV of the project would be zero, is 344€/tCO_2 in 2010. If Reykjavik Energy is to continue injecting at this pilot phase CO_2 flow rate, the price would need to be 344€/t, and inflate 5% per year, in order for there to be no financial loss.

3.2.2. HFS scenario

The HFS scenario results in a break even (NPV equal to 0) required price of 22.5€/tCO_2. The IRR requirements of 15% and 20% increase the price of CO_2 to 25.8 and 31€/tCO_2, respectively. Fig. 6 shows how each factor of the economic system contributes to the net NPV when the price is 31€/tCO_2. The project capital represents the 30% of the 11.54M€ capital cost that is financed by equity. A majority of the cost contribution is referenced to the capital costs of the project.

3.2.3. MRE scenario

The MRE scenario results in a break even required price of 9.3€/tCO_2 in 2010. The two higher prices are 10.5 and 12.3 for a required IRR of 15% and 20%, respectively. Fig. 7 shows the itemized NPV contribution when the highest price is used.

Comparing Figs. 6 and 7 shows the larger contribution by water and electricity costs in the MRE scenario. Fig. 8 shows also the marginal NPV that results from the two IRR based prices for each scenario. In the HFS scenario an IRR requirement of 20% only gives a marginal NPV, or additional value, of 3M€ rather if the required IRR had been 15%. In the MRE scenario however the marginal NPV through a higher IRR requirement is 8M€. This shows that when CO_2 flow rates are small the system demands either a high IRR or a lower initial investment in order for the system to be as econom-

[5] Original figure given in USD and adjusted according to the exchange rates used in this article.
[6] This is only theoretical to examine the costs this reservoir would sustain if it were able to store this high flow rate.
[7] The present fluctuating market price per tonne of CO_2 can be found in http://www.pointcarbon.com. Prices accessed May, 2009 and may have changed.

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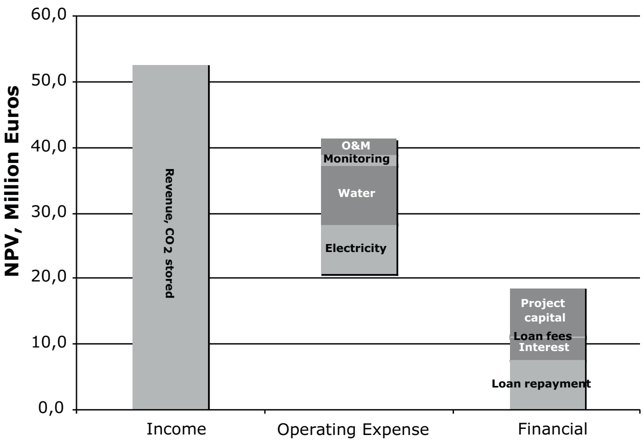

Fig. 7. MRE scenario at 12.3€/tCO_2 price with itemized contribution to the net NPV of 13.3M€.

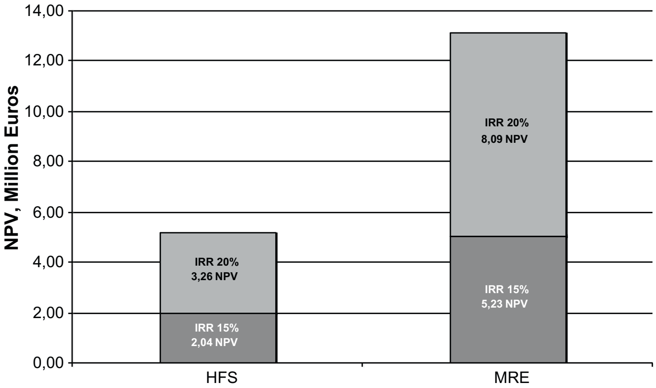

Fig. 8. Marginal NPV of the HFS and MRE scenarios as the minimum IRR requirement increases.

ically appealing as a system with high flow rates, and thus lower IRR requirements.

Fig. 9 demonstrates an interesting conclusion when the value per tonne CO_2 stored is compared in the two scenarios. The value per tonne is calculated as the revenue received through the CO_2 price minus the variable costs, loan repayments and depreciations. This total is divided by the total CO_2 stored per year. After 2018 the HFS provides the investor with a higher value per tonne CO_2 stored than the MRE scenario, regardless of which IRR requirement is used. This is due to the fact that the HFS scenario is

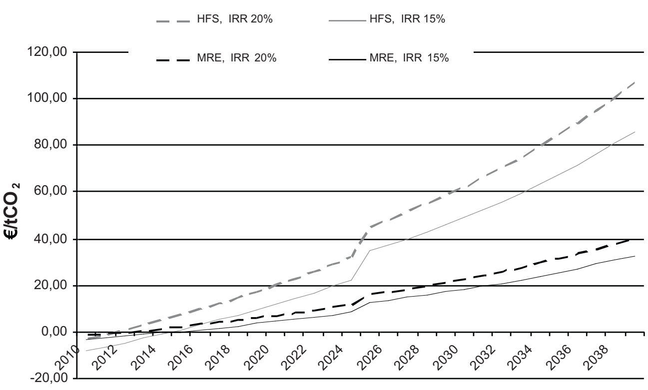

Fig. 9. Value per tonne CO_2 stored to the investor at differing minimum IRR requirements.

able to retain a better cost revenue ratio. The cost revenue ratio is the efficiency at which costs are minimized per each unit of revenue. By the end of the project life, with an IRR requirement of 15%, the HFS scenario has a ratio of 81% while MRE scenario only 76%.

The explanation lies in the fact that the MRE scenario, with its higher CO_2 flow rate, requires a larger volume of water and a higher energy requirement. In the HFS scenario the contribution of electricity and water in the last year of the project is 29% and 20%, respectively. But in the MRE scenario these values are 35% for electricity and 40% for water.

4. Conclusions and recommendations

This paper reviews the cost analysis for three scenarios, based on the CarbFix Pilot P (CPP) project at Hellisheidi power plant in Iceland and previous research. The cost analysis is used for the purposes of a profitability assessment. The first scenario is the pilot project itself and its current operations. Two scaled scenarios are cost assessed, based heavily on the known costs of the pilot program; Hellisheidi Full-Scale (HFS) where the flow rate is 1.8 kg/s CO_2 and Maximum Reservoir Exploitation (MRE) with a flow rate of 12.7 kg/s. For the specific reservoir at Hellisheidi, the maximum amount that can be stored annually, with a prerequisite that the reservoir capacity be filled in no sooner than 30 years, is 400,000 tonnes CO_2.

The conclusions of the research are partially in line with the original analysis performed by Ragnheidardottir (2010). The cost of storage in the pilot scale CPP scenario is confirmed to be high, at 502.7€/tCO_2, and characterized by high capital costs in the form of wells, both injection and monitoring wells. The resulting costs are 29.9 and 12.5€/tCO_2 for the HFS and MRE scenarios, respectively. The costs for sequestration at this reservoir at current operating conditions will be primarily subject to the flow of CO_2 being stored. The pilot project is heavily weighed in capital costs but as the flow increases the annualized capital costs are overshadowed by the annual costs that are in the form of electricity, water, O&M and monitoring. These variable costs follow the CO_2 flow rate where the capital costs are not scaled linearly. From 50 to 400 thousand tonnes of CO_2 the electricity plays the largest role in variable costs but after this threshold is overtaken by the costs of water. Therefore if this reservoir is to be used under the constraints that 400 thousand tonnes is the maximum amount of CO_2 to be injected annually, in order to exploit the reservoir for 30 years, the costs attributed to electricity should be the area of focus for cost reduction.

However, as research into the reaction rates at the injection site continue the number of injection wells will increase. The number of monitoring wells required to monitor the plume is also a likely possibility for capital cost increases and should be reviewed again to determine the increased weight of capital costs on the system. If the reservoir is found to be able to receive more than 400,000 tonnes per year or the exploitation on a short time frame is required, the water costs will likely be the main avenue for cost reductions. More research should be carried out to study the water requirement to acquire the correct reactions and minimize water and power usage, if possible. As other sites are studied for the possibility to employ the CarbFix method of storage, especially if large point CO_2 sources are available, the influence of water on energy and cost may play a more important role.

The profitability assessment results in a break even price of 344€/tCO_2 for the pilot program; a price that is uneconomical at the current trading and regulatory prices. The MRE and HFS scenarios however present price results that are well within known market prices for CO_2 as well as documented taxes. Both scenarios present

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two prices based on minimum IRR requirements of 15% and 20%. The lower the minimum IRR the lower the required price of CO_2 on the market in order for the system to provide a reasonable profit. The HFS scenario at the two IRR requirements, 15% and 20%, results in a CO_2 price of 25.8 and 31€/tCO_2, respectively, while if the price is at least 22.5€/tCO_2 the system would operate at zero profit. These figures are equivalent to known CO_2 taxes in Europe. The MRE scenario produces prices of 10.5€/tCO_2 for the 15% IRR requirement and 12.3€/t for the 20% requirement while the break-even price is 9.3€/tCO_2.

From the perspective of an investor there is a trade off between a low CO_2 flow system and a high one in long or short-term goals. When the CO_2 flow rate is low the system requires that the initial investment be lower than what the current costs call for in order to make it as appealing as a high CO_2 flow rate system. This seems quite obvious because the NPV, and resulting IRR, are influenced by the initial investment. By increasing the required IRR from 15% to 20% the marginal NPV in the HFS scenario is minimal compared to the same increase and financial achievement in the MRE scenario. However, when the value of the CO_2 stored, taking into account not only costs but also the financial return on quotas, the lower flow rates progress better. This is due to the fact that eventually the capital will be amortized, until the cost no longer exists, but that the variable costs such as water and electricity will always be present and integrated with the CO_2 flow rate. An investor must be very aware in this case of their financial goals and what opportunities alternative projects offer.

In light of the findings it is recommended that the CarbFix project continues assessing the requirements, both variable and capital, as well as examine which costs are specific to the site itself. That is, will the electricity and water requirements be similar in other reservoirs with varying temperatures and pressures. The reaction rates will also largely determine the number of injection wells and may alter the findings of this research. However, it is unlikely that after a certain flow rate threshold that the capital costs will outweigh the electricity and water requirements, as they stand today. The CarbFix method employed elsewhere in the world is unlikely to encounter such low CO_2 point sources. The findings should also be reassessed once firm regulations on monitoring, both during and post-closure, have been formed. Additionally, it should be assessed not only how many monitoring wells are needed but also the location of the wells throughout the life of the injection and post-closure. All of these factors will affect the cost model for CarbFix and its future position as a competing carbon storage technology.

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