Carbon Capture and Storage Energy Systems vs. Dispatchable Renewables for Climate Mitigation: A Bio-physical Comparison

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**Abstract**

Mainstream sources, like IEA and most Integrated Assessment Models such as those described in the IPCC reports, consider carbon capture and storage (CCS) as a critical technology component for reducing CO2 emissions in view of mitigating climate change, especially when considering net negative pathways, such as bio-energy coupled with CCS (BECCS). Nevertheless, the actual installed CCS capacity to date (110MWe installed by 2016) is so small that it is legitimate to be concerned about its ability to scale to levels that would provide a significant mitigation impact within the timeframe for de-carbonization involved in the Paris 2015 treaty. Conversely, renewable energy (RE) installations can be considered an alternative climate mitigation approach for the energy system, currently operating at a much greater scale, with likely potential to expand much more rapidly. This observation raises the question of whether the effort of reducing CO2 emission would be better accomplished by investing the available resource in renewable technologies rather than in carbon sequestration. In the present paper, we compare CCS and RE as electricity generation technology pathways using a physical metric, energy-return-on-energy-investment (EROEI). We develop a generalizable methodology for deriving the EROEI of CCS projects accounting for their operational and infrastructural energy “penalties”. In order to make an equivalent comparison, we include energy storage to allow for fully dispatchable RE. We show that RE without storage, as is the case in its large-scale integration so far, outperforms any form of energy CCS project by EROEI. With storage, some low EROEI RE have an energy return comparable to that of high efficiency CCS but, overall, no significant advantage for CCS can be determined. Finally, we include ancillary considerations on the utilization pathway, geological, and infrastructural requirements to conclude that CCS as a power resource is unlikely to contribute significantly as a bridge for the transition effort. A more energetically effective approach to climate scale mitigation is simply to divert the resources that might have been used to deploy CCS for power systems to further expand RE deployment.

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# Introduction

Conventional approaches to climate change impact mitigation place a very significant reliance on carbon capture and storage (CCS), recognizing it as a critical component in future energy portfolios. In IEA’s 2012 scenarios, CCS contributes around 14% of needed emissions reductions by 2050[[1]](#footnote-1) 1. In mainstream Integrated Assessment Models (IAM) for cumulative emissions of 1000GT CO2 or less (consistent with RCP2.6), CCS contributes anywhere from 5% to 55% of the total primary energy with the regressed average exceeding 20%2. In addition, CCS is at the basis of the concept of negative emission technologies, also referred to as bio-energy CCS (BECCS), whose contribution in future scenarios in a recent study ranged from a maximum of -55 Gt CO2/yr down to -5 Gt CO2/yr depending on the levels of early mitigation3.

However, we note a few trends that contradict the postulated ability of CCS to scale in the timeframes involved. Current deployment figures lag noticeably, with only 110MWe of power CCS installed by 20164. Also notably, China the single largest emitter that was expected to develop 349GWe of CCS power by 2050 in the IEA 2DS, has not included CCS as part of their nationally determined contributions (NDC) submission to the 22nd Conference of the Parties in Morocco nor does it have any large-scale CCS in operation. Comparing the 110MWe of CCS to the 227,000 MWp of PV and 433,000 MWp of wind cumulatively installed by 2016 5 a significant gap between modeled expectations for CCS and practice emerges (shown in Table 1). Simply put, the fossil fuel with CCS approach as a transitional power resource does not appear to have an impact comparable to that obtained by the diffusion of renewable energy (RE). While these difficulties are acknowledged6, the reasons behind them require further investigation. We believe that one way to explain the handicap of CCS compared with RE technologies is its lower net-energy return, i.e. CCS requires a larger energetic investment to deliver the same level of electricity services and by implication achieve the same level of emission reductions compared to RE.

Table 1 Current Installed Base and Comparison with IEA 2DS (2 decree scenario) targets (Data source: 1, 7)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Installed Base (GWp)** | | **IEA 2DS Projections (GWp)** | **Annual Growth Rate** | **Growth rate needed to achieve 2DS target** | **Share achieved** |
| **Year** | 2012 | 2016 | 2050 | 2012-16 | 2050 | 2016 |
| **Power CCS** | 0 | 0.11 | 964 | - | 30.6% | 0.01% |
| **Scalable RE** | 370 | 670 | 8785 | 20.27% | 7.8% | 7.63% |
| **Biomass** | 52 | 65 | 440 | 6.25% | 5.8% | 14.77% |
| Note: Figures from authors' calculations based on IEA and IRENA data | | | | | | |

Net energy analysis is an important tool for energy systems planning, providing a measure of the relative utility of an energy delivery technology in the form of the final energy made available to society after subtracting the energy used in its delivery8. While there exist several lifecycle assessment (LCA) analyses for CCS 9, 10, 11 none presented a net-energy analysis or a comparison with RE. In a net-energy study of coal liquefaction in China, “extremely low, even negative net energy returns were reported12. A 2006 CCS and RE comparison in the German context did not evaluate net-energy performance but found that, on a lifecycle basis, CCS emissions are considerably greater compared to off-shore wind farms in the North Sea and solar thermal plants in North Africa per unit of energy delivered 13. To our knowledge, no general net-energy evaluation of CCS and RE is available. We cover this gap by presenting a general framework for estimating the EROI of CCS energy systems and comparing them with RE resources. This approach allows us to determine under which circumstances CCS energy could be competitive with RE from a net-energy perspective.

In addition to net energy performance, we also discuss (*i*) CCS scaling potential and the effects of fossil fuel resource depletion, (*ii*) location dependence on the availability of carbon storage reservoirs, (*iii*) the risk associated with reliance on its future deployment (for negative emissions), and (*iv*) the fact that CCS does not feasibly capture 100% of the carbon emission stream in the flue gas.

Our analysis is specifically targeted to the use of CCS solely in association with electric power generation with a fossil fuel input. It does not apply to CCS processes associated with non-electric, energy conversion practices, such as processing of oil and gas. Nor does it apply to energy utilizing activities, as in industrial processes like steel or cement production because the primary functional output is not energy. For the case of bio-energy CCS (BECCS), the atmospheric carbon removal is the priority and the energy output is an ancillary co-product although the other arguments against CCS (see Section 4) remain relevant. Finally, we do not consider “carbon capture and utilization”, i.e. the capture and subsequent use of the CO2 stream for industrial uses like the manufacture of fuels or chemicals, since these kinds of processes are dual-use allowing the eventual release of the carbon into the atmosphere and therefore have no long-term climate mitigation effect.

Section 2 overviews the net energy analysis approach and clarifies an important issue with regards to handling internal energy flows. Section 3 presents an overview of the variety of energy CCS approaches and discusses the EROI of energy systems. Section 4 develops a generalizable method to calculate the EROI of a CCS-enabled process based on the EROI of the equivalent process without CCS. Section 5 compares the EROI of CCS and RE systems.

# A Brief Overview of Net Energy Analysis

The energy return on energy investment (ERoEI or EROI) is a measure of the ratio of available energy that a process provides (Eout) over the energy that needs to be expended during the process (Ein). As a physical measure, EROI presents an alternative to monetary-based comparisons with distinct advantages8. Nevertheless, determining the EROI of a process requires attention because it depends on the boundary of the analysis and it is specified in five accounting levels: internal energy, external energy, material energy, labor, and ancillary services of energy use14. The common accounting boundary considered as standard14 includes the first three. The energy investment will include the capital energy investment embodied in the materials and used for the construction and eventual decommission (*Ecap*), and the operational investment for procuring and distributing the fuel itself (*Eop*). If we denote as R the ratio of Eop/Ecap we reach the final form of Eq. 1.

Eq. 1

A subtle but important consideration in the calculation of the EROI for chained, multi-step processes is how to handle internal energy use. Should the high-quality energy that becomes available from an upstream step but is then used in a transformation at a downstream step be considered as an input or not? In essence, choosing to ignore internal energy use omits the opportunity cost of directing that energy to other purposes 15. This results in masking the overall process actual energy costs potentially overestimating its energetic performance16. While we recognize this potential weakness, we opt to assess fossil system EROI using only the *net* energy outputs and without accounting for the internal energy streams. This option offers a simple energetic calculus clearly indicating how much energy needs to be invested to deliver a given amount of electricity. Moreover, for electricity generating systems, process efficiency can increase by adding internal energy exchange steps (e.g. using a combined Rankine and Brayton cycle system) as opposed to operating them individually. Considering such internal process energy flows outside the boundary, would lead to, counterintuitively, lower EROI for the combined system. Finally, the choice of omitting internal energy streams is conservative as it provides the higher range of estimates of EROI for CCS processes. We use this approach to develop a generalizable approach to estimate the EROI of CO2 harvesting processes with CCS in Section 4.

# CCS characteristic energy penalties and EROI of fossil systems

The first step of CCS, capture, is well understood and there exist a variety of technology options for carbon capture from fossil fuel combustion 17 18. Pre-combustion through gasification allows the separate combustion of the carbon and hydrogen fuel components and thus easier capture of CO2. Post-combustion, which is the only currently commercialized process, separates the CO2 present in concentrations of 5-15% from the flue gases of conventional combustion systems. It is also possible to utilize oxy-fuel combustion, that is combustion with high oxygen concentration, to produce effluent gas with correspondingly high concentrations of CO2. Post-combustion processes include physical methods, such as cryogenic separation, chemical capture in solvents such as amine solutions, orionic liquids, electrochemical or plasma activation of CO2, and more. In practice, the commercially considered methods are either post-combustion separation via amine solutions or oxy-combustion although in practice the latter seems to face additional obstacles in utility-scale deployment.

The captured CO2 needs to be transported, compressed for ease of handling, via pipeline or ship to the location where it will be processed and stored. This final step of the process involves storing the CO2 in forms expected to remain stable at least for a few centuries. Storage may be achieved by pumping the CO2 gas into an appropriate geologic formation, usually saline aquifers, depleted oil and gas reservoirs, or active oil reservoirs for enhanced oil recovery (EOR). There, it would be further compressed and injected underground through drilled wells for geologic storage. Other proposed methods involve storage in abandoned mines, the injection of liquefied CO2 at the bottom of oceans, and chemical sequestration, that is transforming CO2 into a solid product such as pure carbon or carbonates. This diversity in possible combinations of capture and storage makes a comprehensive and detailed net energy analysis of each combination impractical leading us to create a generalized CCS EROI methodology (see Section 4).

All four CCS steps of separation, compression, transport, and injection (or chemical removal) require primary energy that should be subtracted from the gross energy output of the plant as an operational energy penalty. Nevertheless, these steps also entail infrastructure investment for the capture or air separation units, the compressors, and the pipelines that translate into additional embodied energy, or capital energy penalty. Both should be considered.

## Energy Penalties of CCS energy systems

We distinguish two types of energy penalty; those arising from operating the CC process, and those from the construction of the CC plant. These are described in more detail below.

### Operational energy penalties

Operational energy penalties result from: *i*) the withdrawal of thermal energy from the steam-cycle, usually for amine regeneration, thus reducing *gross* electricity output and *ii*) from the use of electric power to operate ancillary equipment for capture and transport processes like pumps and compressors that reduces *net* electricity output. These operational energy penalties (*f*op) are defined as the ratio of the reduction in *net* electricity *with* a CCS process over the *net* electricity output *without* CCS.

A strategy for mitigating the first aspect is to integrate low-grade heat sources like solar thermal in the plant design 19, while for the second is to optimize process step integration20. Parameters that influence the per-unit (e.g. per kg of CO2 captured) and total operational penalty are: *capture ratio (CR)*, i.e. the ratio of the CO2 that is captured from the flue-gas stream, *fuel type*, and *the power generation process and its efficiency* (see Table 3)21. The optimal energy penalty per kg of CO2 for pulverized coal plants is achieved at *CR* between 65% and 80% 22 - though most designs aim for the maximum practical *CR* of 90%.

Recognizing the importance of mitigating the energy penalty, significant progress has been achieved, halving it for solvent regeneration from 450 kWh/tCO2 in 2001 to 200 kWh/tCO2 in 201218. Nevertheless, the operational energy penalty for a complete CCS cycle remains significant. Applying first principles to a pulverized coal (PC) system, the absolute lower bound for *fop* is estimated at 11% while 29% is considered a reasonably practical target for 90% *CR* 23. These data imply that more than one fourth of the gross electricity output of the plant must be used for CCS.

For transport, CO2 must be purified and compressed to allow for transport as a supercritical fluid and avoid two-phase flow problems in the pipeline. A CO2 flow of about 1.5 million tonnes per year, produced from a baseload 530MW CCGT plant, requires compression power of about 23MW or 4.3% 24. For distances greater than 100km, this becomes insufficient and repressurization stations would be needed along the way. Final pressurization and treatment before injection may be necessary as well. In addition to these costs, monitoring of the injection site needs to be included as an operational investment.

The theoretical estimates are confirmed from detailed simulation of several IGCC (integrated gasification combined cycle), PC, and NGCC (natural gas combined cycle) configurations with and without CCS, shown in Table 3. These values include the pressurization, transportation and injection components for a favorable saline aquifer injection site 80 km distant25. In the post- and pre-combustion cases, the fuel type plays a significant role on the energy requirements of the capture process. The average capture penalty (*fop*) is 28.3% for PC, 21.3% for IGCC and 14.7% for NGCC. The energy penalty for a coal-to-liquids (CTL) plant with post-combustion capture is 45% 12.

### Capital energy penalty for CCS

The infrastructural energy penalty (*fcap*) is the ratio of the energy embodied in the CCS system over the energy embodied in a conventional power plant. This can be estimated using a detailed LCA procedure. In the absence of such, a good approximation is offered by environmentally-extended input output analysis 26. Based on plant costs presented in Table 2, we use the US 2002 producer model to estimate the energy requirements of the plant investment the intensity is 5.49 TJ per million 2007 USD[[2]](#footnote-2). Using this approximation, the *fcap* estimate, ranges from around 40% for IGCC, 80% for PC, and more than 100% for NGCC.

While these estimates account for transport pipelines and compression under favorable conditions, actual values in large-scale adoption would likely be higher as a longer transportation network would be needed. Widely-used approximation models to estimate pipeline capital and operation costs can be simplistic and lead to underestimating the costs unless based on pipeline weight 27. The optimal design of the pipeline network becomes complicated as it depends on the ability to pool together several sources and build trunk pipelines to utilize scale economies 28,29. In practice though costs and risks may favor an incremental project-based approach with point-to-point pipeline as developments depend on future carbon price expectations that can be subject to significant uncertainty at the time of investment decisions. In this case, the per stored tonne cost of a point-to-point system may be anywhere from 30% to 350% higher than would be the case for an optimal network 30. Conversely, a compounding uncertainty acting on the opposite direction is the level of renewable energy adoption and the concomitant reduction in the utilization of CCS fossil-fired power plants that could imply that a smaller size pipeline investment may be appropriate 31.

## EROEI of fuels and electricity generation systems

In order to evaluate their relative performance, this section reviews the EROEI of the fossil options (IGCC, PC, and NGCC) together with the EROEI of dispatchable scalable RE. The EROEI of the fuel is reported separately and we denote that we the suffix *th*. The EROEIe referring to the electricity output, needs to additionally account for the conversion efficiency (*η*), the power-plant invested energy (*Ecap*) and the operations and maintenance expenses (*EO&M*). There is significant divergence in the literature reported EROEI for fuels. Using a monetary basis for the calculation, Freise estimates the Canadian conventional natural gas EROEIth in 2009 as 20 from a peak of around 80 in 1970s 32. A more detailed material analysis estimated the average EROEIth of tight gas wells drilled in Indiana in the period between 1985 and 2003 at 8733. The most recent estimates for coal EROEIth range from 23 to 5834. The general trend is that resource depletion increases the energy intensity of the extraction processes and the fuel’s EROEI drops.

For the case of RE, EROEI depends on the energy costs to build the plant but also on the resource quality of the area the system is installed. Given the very steep learning and scale economies curves, a normalization study demonstrated the importance of using the latest information for accurately representing the state-of-the-art 35. A recent meta-analysis harmonized the inputs of several assessments and found that the average EROEIe of PV ranges from 8.7 for mono-Si to 34.2 for CdTe36. Noting that the latest inputs of the study came from 2011 and that PV technologies have demonstrated significant technological learning curves, EROEIe for PV are estimated to be currently around 25 to 40 in areas of moderately good insolation37. For wind energy, a similar meta-analysis found normalized EROEIe consistently over 10 for large turbines, with several studies reporting values over 3038. Despite the uncertainty in these measurements and the relatively large spread in the data reported in the literature, overall, the two technologies that offer the highest scaling potential, solar PV and wind both have EROEIe greater than 10 even when installed in moderate quality resource areas.

An argument often raised against scalable RE resources is their variability 39. At current adoption rates, renewable energy has been integrated directly into the electricity grid without the need for deploying additional storage simply by utilizing the extant abilities of the power system to modulate supply and demand. Such facilities include utilizing electricity trade and long-distance transmission lines {Jaehnert:2013gc}, dispatchable and flexible powerplants (mostly hydro and gas), cheap sources of storage like pumped-hydro, and demand response through wholesale electricity markets that may include curtailement {Jacobsen:2012eh}. At higher adoption rates this status will become increasingly challenging {Ueckerdt:2015eb} yet manageable {Frew:2016dq}. Therefore, in order to compare fossils and renewables on an equal basis, we account for the use of energy storage systems that can make them fully dispatchable 40. To do this on a net-energy basis, we use the concept of energy-stored-on-energy-invested (ESOI), for a storage fraction (*φ*) and storage cycle efficiency (*η*), to estimate the EROEI of the combined generation + storage system using Eq. 241. This approach is agnostic to the storage medium and can work equally well for batteries, thermal storage and pumped-hydro. Since it assumes electricity to electricity conversions, it satisfies all other ancillary balancing requirements.

Eq. 2

The ESOEI of different options is practically bimodal with batteries having low values on average around 16 while pumped-hydro and compressed-air return very high values exceeding 70041. For our calculations we consider a few scenarios. First, we report the no-storage case, which is representative of the current small penetration levels. Using the results from a detailed hourly country-level energy model including energy trade 42, we estimate the average system battery storage fraction at a global scale at 10%. Based on an alternative method, using residual load duration curves, an average regional curtailment level (used for storage) was estimated at 20% 43. In order to ensure a conservative estimate, we also consider a 40% storage fraction with the worst case option of battery-only storage noting that since battery technology is also improving dramatically44 higher ESOI ratios will be achieved. Finally, a chemical storage option (P2L2P) may also be deployed for seasonal storage needs and to mitigate curtailment. One such proposal envisions a two-tank, closed loop system that circulates carbon as the carrier molecule through a reversible solid oxide fuel cell. In charging mode, stored CO2 and water are processed through fuel cell stacks with electricity input to generate a mix of methane, hydrogen and carbon monoxide that is stored under pressure. The reverse process takes place in discharging mode with electricity as output providing an estimated 70% round-trip efficiency at intermediate cell temperatures (680C) {Wendel:2015jz}.

# Generalizable net-energy analysis of CCS energy systems

Figure 1 shows a schematic fossil-fuel fired coal/biomass plant along with a CCS option in order to demonstrate the corresponding energy flows and EROEI estimation after accounting for the process energy penalty flows. Eq. 3 shows the conventional EROEI estimate. Eq. 4 shows the relationship to cycle efficiency (*η*), plant-lifetime (*L*), and capacity factor (*cf*) for installed capacity (*P*). The energetic cost of the power-plant infrastructure is a product of the unit capital cost (*C*), (*P*) and the capital energy intensity (*i*). Operation and maintenance (EO&M) is referenced as a share (sO&M) of the investment cost. Finally, the fuel procurement costs can be calculated by dividing the higher heating value of the fuel (HHV) with its EROIth (see Section 3.2).

Eq. 3

Eq. 4

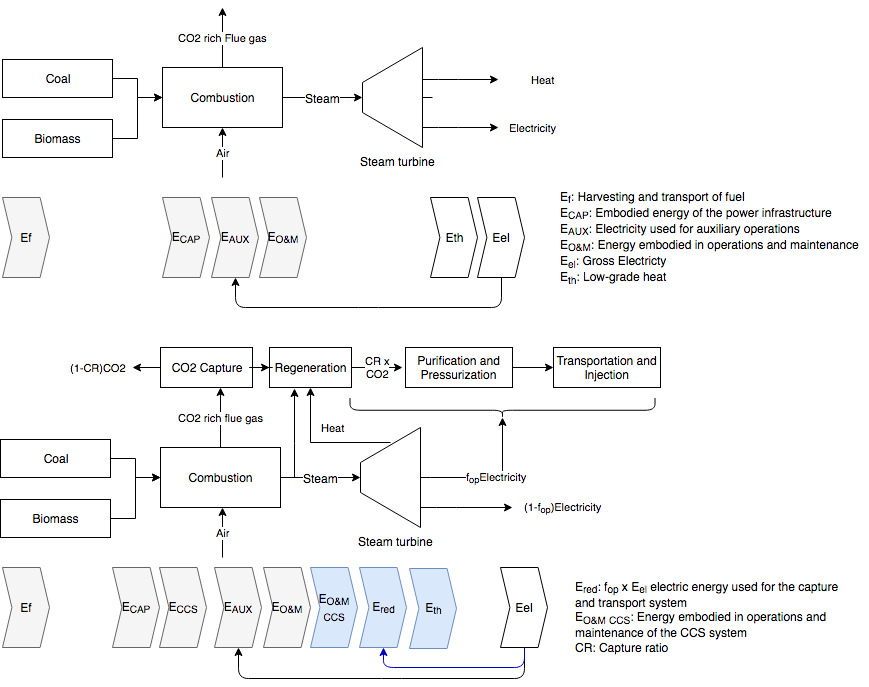


Figure 1 Simplified process and energy flow diagrams for an electricity plant without (upper) and with CCS (lower) with the corresponding EROI equation. Grey: inputs, White: outputs, blue: redirected flows from external to internal

Using Eq. 3 to include the CCS process leads to Eq. 5. The re-purposed energy flows that were previously available as an output are subtracted from the numerator (energy out) while the additional capital and operating investments for the CCS plants are added to the denominator. We can then divide Eq. 3 and Eq. 5, generalizing, for a given capture ratio (*CR*) and using the same fuel input we can write Eq. 6. Defining the known ratio of fuel to capital and operating energetic costs (R= Ef/(Ecap(1+Ls)), we can simplify Eq 6. to Eq. 7.

Eq. 5

Eq. 6

Eq. 7

From Eq. 4 and Eq. 7 we can therefore determine the primary drivers for the EROEI of CCS processes and its relationship to conventional. also provides through simulation and First, the CCS EROEI is higher when the conventional process has a high EROEI itself. High capacity factors, long asset life, low O&M costs and especially a high EROEIth are positively contributing factors. If the capital and operating energy expenses increase as a result of less favorable injection locations, then they would negatively impact the CCS EROEI. Finally, lower capture ratios, decrease both the operational and capital penalties at the expense of more atmospheric carbon release.

Table 2 Normalized Performance Characteristics of Coal and Natural Gas Plants with and without CCS for 90% Capture Rates, 85% Capacity Factor, and 80km Pipeline to Injection

(Data source: 25 and author calculations)

|  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | **Coal Integrated Gasification Combined Cycle**  (Based on NETL Exhibit 3-101 *and normalized for coal flowrate =500000 lb/hr*) | | | | | | **Pulverized Coal**  (Based on NETL Exhibit 4-58 *and normalized for coal flowrate =500000 lb/hr*) | | | | **Natural Gas Combined Cycle**  (Exhibit 5-27) | |
| **Case number** | **1** | **1a (CCS)** | **2** | **2a (CCS)** | **3** | **3a (CCS)** | **4** | **4a (CCS)** | **5** | **5a (CCS)** | **6** | **6a (CCS)** |
| Gross Power Output (kWe) | 800,812 | 753,576 | 802,465 | 726,645 | 843,933 | 723,675 | 666,014 | 546,916 | 708,621 | 585,699 | 564,700 | 511,000 |
| Aux Power Requirement (kWe) | 134,665 | 195,837 | 122,989 | 196,288 | 123,693 | 189,720 | 37,245 | 99,790 | 37,128 | 99,705 | 9,620 | 37,430 |
| Net Power Output (kWe) | 666,148 | 557,739 | 679,475 | 530,357 | 720,240 | 533,955 | 628,770 | 447,126 | 671,493 | 485,994 | 555,080 | 473,570 |
| Net Plant HHV Efficiency (%) | 39.0% | 32.6% | 39.7% | 31.0% | 42.1% | 31.2% | 36.8% | 26.2% | 39.3% | 28.4% | 50.2% | 42.8% |
| Plant Overnight Cost (2007$/kW) | 1,987 | 2,711 | 1,913 | 2,817 | 2,217 | 3,181 | 1,622 | 2,942 | 1,647 | 2,913 | 584 | 1,226 |
| Plant Costs ($million) | 1,591 | 2,043 | 1,535 | 2,047 | 1,871 | 2,302 | 1,080 | 1,609 | 1,167 | 1,706 | 330 | 626 |
| Eout (GWh) | 178,885 | 168,334 | 179,255 | 162,318 | 188,518 | 161,655 | 148,774 | 122,170 | 158,292 | 130,833 | 126,143 | 114,147 |
| Ecap-ccs (GWh) |  | 688 |  | 780 |  | 657 |  | 806 |  | 821 |  | 452 |
| Ecap (GWh) | 2,425 | 2,425 | 2,339 | 2,339 | 2,851 | 2,851 | 1,646 | 1,646 | 1,778 | 1,778 | 503 | 503 |
| EO&M | *2,910* | *3,736* | *2,807* | *3,743* | *3,421* | *4,209* | *1,975* | *2,942* | *2,134* | *3,120* | *603* | *1,146* |
| Ef (GWh) | *7,908* | *7,908* | *7,785* | *7,785* | *7,720* | *7,720* | *6,970* | *6,970* | *6,944* | *6,944* | *2,888* | *2,888* |
| EROIth | 58 |  | 58 |  | 58 |  | 58 |  | 58 |  | 87 |  |
| EROIel (Eq. 3 ) | **11.2** | **8.4** | **11.7** | **8.1** | **11.5** | **7.7** | **13.3** | **8.1** | **13.8** | **8.6** | **31.0** | **21.2** |
| EROEI\_CCSest (R first col) | **1.5** | **8.2** | **1.5** | **7.7** | **1.2** | **7.1** | **1.9** | **7.4** | **1.8** | **7.8** | **2.6** | **20.3** |
| ***fop*** |  | ***16.3%*** |  | ***21.9%*** |  | ***25.9%*** |  | ***28.9%*** |  | ***27.6%*** |  | ***14.7%*** |
| ***fcap*** |  | ***36.4%*** |  | ***47.3%*** |  | ***43.5%*** |  | ***81.4%*** |  | ***76.9%*** |  | ***109.9%*** |

# CCS vs. Dispatchable RE

In order to assess the varying impact of these factors and compare them to the performance of renewable sytsems, we conduct a factorial analysis across ranges. The operational energy penalty (*fop*) ranges from 14.9% to 28.9%, excluding transport, for the CCS technologies shown in Table 1. Combining the values of the fossil and RE with the fop estimates and applying Eq. 5 we have the derivative EROI estimates between dispatchable RE and CCS for power generation shown in Table 3. We observe from the comparison of the EROICCS and EROIdisp is that only the worst cases for RE are comparable to the best case for CCS. This is also graphically demonstrated in Figure 3.

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | Range (%) | | | |
| Technology | Fop | fcap | CF | CR |
| CCGT Gas | 12-20 | 80-140 | 50 and 90 | 50 and 90 |
| Pulverized coal | 25-35 | 75-100 | 50 and 90 | 50 and 90 |
| IGCC coal | 15-30 | 30-50 | 50 and 90 | 50 and 90 |
|  |  |  |  |  |
|  |  |  |  |  |

Table 3 Reported (bold) and Derivative EROEI values for Fossil and RE Power Resources

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Case** | **Fossil Fuels** | **EROEIth** | **Technology** | **EROEIe** | **EROEICCS** |
| ***A1 A2*** | *Conventional Canadian Gas (Freise 2011)* | ***20 (2009)*** | 6a, CF=85%  6a, CF=45% | 9.1  8.5 | 7.2  6.4 |
| ***B1***  ***B2*** | ***80 (1970)*** | 6a, CF=85%  6a, CF=45% | 29.1  23.7 | 20.2  14.9 |
| ***C1***  ***C2*** | *Tight Gas Indiana*  *(Sell et al. 2011)* | ***87 (2003)*** | 6a, CF=85%  6a, CF=45% | 31.0  24.9 | 21.2  15.4 |
| ***D*** | *Coal (Kong 2015)* | ***23*** | 7 | 7 | 4.7 |
| ***E*** | *Coal (Hall et al. 2014)* | ***58*** | 13.8 | 13.8 | 8.6 |
|  | **Renewables** |  |  |  | **EROIdisp** |
| ***F*** | *PV*  *(Bhandari et al. 2015)* |  | ***10*** | ***10*** | 7.6 |
| ***G*** | *PV (Raugei et al. 2017)* | N/A | ***40*** | ***40*** | 20 |
|  |  |  |  |  |  |
| ***H*** | *Wind(Davidsson et al. 2012)* |  | ***10*** | ***10*** | 9 |
| ***I*** | N/A | ***33*** | ***33*** | 29.3 |

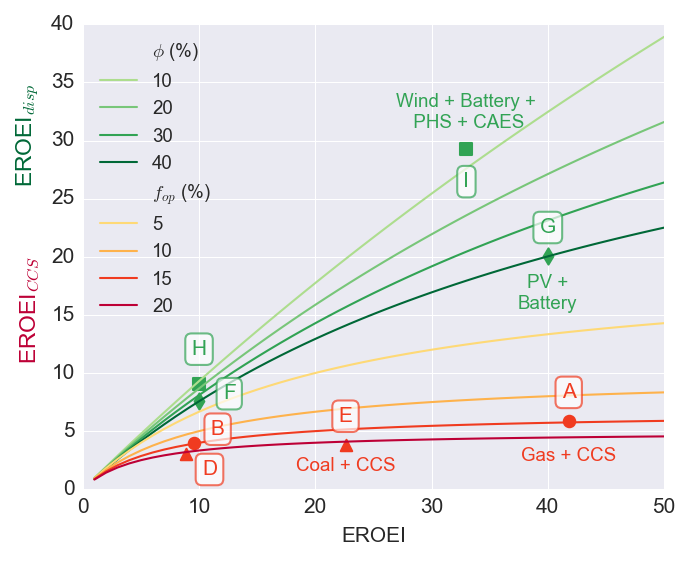
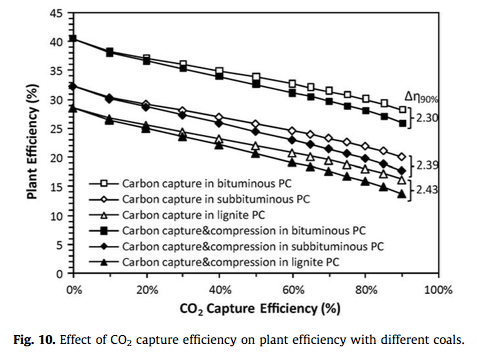


Figure 2 Parametric Relationship of EROICCS with EROIdisp.

Since the values in Table 1 are estimated based on an assumption of 90% CR, it is still useful to consider how different CR and CF ratios impact the EROI. For this analysis, we use the electricity penalty data to define the operational energy requirement for CCS reported across different possible capture ratios from 0 to 100% CO2 capture 22 and CF ratios from 50% to 90% using otherwise the same information as Case 5a (cf. Table 2).



This was combined with an assumed 40,000 MJ/MW energy requirement for construction of the power plant [REF], CCS was assumed to be 20% of this, i.e., 8000 MJ/MW; a lifetime of 30 years for both power plant and CCS infrastructure; a 50% capacity factor [REF], and a carbon dioxide emission from combustion of coal of 0.09 kg/MJ [REF].

Figure 4 shows the parametric analysis of the relationship between capture ratio and EROI. For a supercritical PC plant, a *CR* of 25% and above brings the EROEI lower than the CdTe estimate, and at 80% ratio lower than the multi-crystaline estimate.

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Figure 3 Fossil Plants Capacity Factors (source: <https://www.eia.gov/todayinenergy/detail.php?id=25652> )

In summary, from a net-energy perspective, the losses in the fossil primary energy resources from implementing CCS in power generation systems exceed the benefits of simply directing these resources towards building a self-sustaining renewable energy infrastructure, an approach termed the sower’s strategy in previous papers 45.

# Other biophysical considerations on CCS

While the net energy considerations form the most critical problem for CCS scaling, other impediments exist. A critical one is the fact that CCS in fossil fuel power generation, even in its best implementation, does not constitute a zero emissions system since the capture ratio never exceeds 90% of the carbon emissions. In addition, there is a lack of successful pilot projects in diverse geographic locations. The projects that do proceed face significant cost overruns. Finally, there are limited available geologic locations and existing pipeline infrastructure dedicated to CO2 transport, to allow for several regions to implement CCS.

By 2016, the only commercially operational coal-fired CCS plant (110 MW at Boundary Dam, Canada) cost $1.3 billion and registers technical issues, while the major 584MW US project at Kemper Mississipi is expected to cost $6.5 billion instead of the planned $2.4 billion and faced several cancellations 4. We note that these values, adjusted for inflation, exceed by more than three times the anticipated estimates shown in Table 1 at $10,000/kW. Such achievements significantly diverge from the suggested trajectories for a large scale implementation potential 46, 6.

Given the net-energy disadvantages of coal-fueled CCS, natural gas carbon capture (NGCC) may be seen as a more promising option. Yet, this neglects the issue of upstream fugitive emissions in the natural gas extraction and transportation system 47. Also, if these plants are expected to support higher RE penetration their economics will be increasingly affected as their utilization factors would drop and it would be hard to economically justify the additional expense of a CCS facility for a plant that operates as load-follower that fills in the gaps rather than baseload.

Carbon dioxide storage is in itself problematic for several reasons. The main technology proposed so far, geological sequestration of CO2, may create a serious problems since we are replacing non-reactive hydrocarbons with CO2 which is a reactive (acidic) gas, potentially affecting the stability of the reservoir over long time spans. For this reason, it would be safer to transform CO2 into inert, non-gaseous products. One such possibility is to transform CO2 into solid carbon, which is technologically possible either by electrochemical methods 48 or as bio-char. The main problem associated with this concept is that solid carbon is a reactive solid that burns in air and, hence, it could always present a tempting fuel resource or be burned accidentally. These risks can only be mitigated by very deep burial, but the costs of burying a solid is much higher than pumping a gas in an existing reservoir. The last possibility is to transform atmospheric CO2 into carbonates, which are stable and non-burnable, imitating a natural process called “silicate weathering” 49. Unfortunately, this process occurs very slowly in nature. It could be accelerated by human intervention but, at present, there are only tentative proposals which appear very expensive and whose large-scale feasibility is debatable.

# Conclusions

We have estimated the EROI of electricity from fossil-based IGCC, PC, and NGCC with CCS as ranging between 2.4 and 5 while not qualifying as a zero emissions resources. These values compare unfavorably to dispatchable, scalable RE with storage which ranges from 7.6 to 20 even under restrictive assumptions on the storage technology energetic efficiency. Given this factor and the considerations of scaling, economics, and geology, including the fact that CCS is not a true “zero-emission” technology, it appears significantly more profitable, energetically, to invest the available fossil resources directly into further investment in renewable energy. This approach is preferable than retro-fitting or building new fossil fuel power plants with CCS. Perpetuating the reliance on fossil fuels in the form of CCS appears to be both more expensive in terms of net energy and more dangerous in terms of long-term implications of stored carbon. As a result, CCS development should be seen as a niche and supplementary contributor to climate mitigation rather than as fundamental technology option. That doesn't mean that we may not be eventually forced to use some kind of negative emission technologies to cope with a future climate emergency. But we should take into account that such emergency measures will always be expensive and uncertain and would certainly benefit from the existence of installed zero emissions infrastructure.

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