The Cost of CO_2 Transport and Storage in Global Integrated Assessment Modeling

by

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Abstract

Carbon capture and storage (CCS) is one of many critical tools to mitigate global climate change. Much analytic work has been dedicated to evaluating the cost and performance of various CO_2 capture technologies, but less attention has been paid to evaluating the cost of CO_2 transport and storage. This paper assesses the range of CO_2 transport and storage costs and evaluates their impact on economy-wide modelling results of decarbonization pathways. Many integrated assessment modeling studies assume a combined cost for CO_2 transport and storage that is uniform in all regions of the world, commonly estimated at \$10/tCO_2. Realistically, the cost of CO_2 transport and storage is not fixed at \$10/tCO_2 and varies across geographic, geologic, and institutional settings. I surveyed the literature to identify key sources of variability in transport and storage costs and developed a method to quantify and incorporate these elements into a cost range. I find that onshore pipeline transport and storage costs vary from \$4 to 45/tCO_2 depending on key sources of variability including transport distance, scale (i.e. quantity of CO_2 transported and stored), monitoring assumptions, reservoir geology, and transport cost variability such as pipeline capital costs. Using the MIT Economic Projection and Policy Analysis (EPPA) model, I examined the impact of variability in transport and storage costs by applying a range of uniform costs in all geographic regions in a future where global temperature rise is limited to 2°C. I then developed several modeling cases where transport and storage costs vary regionally. In these latter cases, global cumulative CO_2 captured and stored through 2100 ranges from 290 to 377 Gt CO_2, compared to 425 Gt CO_2 when costs are assumed to be uniformly \$10/t CO_2 in all regions. I conclude that the widely used assumption of \$10/tCO_2 for the transport and storage of CO_2 is reasonable in some regions, but not in others. Moreover, CCS deployment is more sensitive to transport and storage costs in some regions than others, particularly China. Several transport and storage options should be taken into account when modeling large-scale deployment of CCS in decarbonization pathways. However, cost data are scarce and there is still a significant amount of uncertainty and variability in available transport and storage costs.

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Acronyms

CCS	Carbon capture and storage
CO_2	Carbon dioxide
EPPA	MIT's Economic Projection and Policy Analysis model
IAM	Integrated assessment model
IPCC	United Nations Intergovernmental Panel on Climate Change
Mtpa	Megatons per annum
NETL	National Energy Technology Lab operated by the U.S. Department of Energy

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1. Introduction

Climate change is one of the greatest threats to public health and safety this century. As humanity continues to pump greenhouse gases into the atmosphere, averting dangerous temperature rise will only get harder (IPCC, 2018). Numerous scientific and international governing bodies have examined the suite of technologies needed to limit global warming to 2 degrees Celsius (2°C) as set under 2015 Paris Climate Agreement (UNFCCC, 2015). Carbon capture and storage (CCS) has emerged as a key mitigation option and refers to the entire process of capturing CO_2 from the exhaust stream of fossil fuel-fired power and industrial plants, and then transporting the captured CO_2 for permanent storage underground or in products. Most analyses indicate that achieving international climate goals will be nearly impossible, if not prohibitively expensive, without carbon capture and storage (IEA, 2020; NASEM, 2019; IPCC, 2014). Deploying CCS technology in the power and other hard-to-abate industrial sectors at the scale required to tackle the climate crisis will challenge decisionmakers and is the focus of many studies.

In analyzing the future role of carbon capture and storage, much analytic work has been dedicated to evaluating the cost and performance of various CO_2 capture technologies, but less attention has been paid to evaluating the cost of CO_2 transport and storage. One reason is because CO_2 capture is widely believed to be the most expensive component of the CCS value chain. However, deploying CCS at the scale needed to achieve global emissions reduction goals will require buildout of infrastructure to transport and store gigaton-scale levels of CO_2. In addition to uncertainty (which refers to how uncertain or missing data can impact the precision of a cost estimate) there is a high level of variability in transport and storage costs – across geologic, geographic, and institutional settings - that is hard to capture in macroeconomic models. In the case of CO_2 transport and storage costs, much of the uncertainty in existing estimates is driven by a lack of extensive experience in building a cost database as opposed to missing or unknown data.

Many well-documented Integrated Assessment Model (IAM) studies combine the cost of CO_2 transport and storage into a single estimate and report costs below \$15 per ton of CO_2 (tCO_2) for most CCS deployment scenarios, and some estimates report costs below \$5/tCO_2 (Herzog, 2011; McCoy and Rubin, 2008; Dahowski et al., 2011). After reviewing these and other studies, the IPCC

Fifth Assessment Report (IPCC, 2014) reported that a common assumption for the cost of transport and storage of CO_2 is \$10/tCO_2. Analysts who model carbon capture, and storage (CCS) technology in decarbonization pathways recognize that CO_2 transport and storage costs vary. The degree to which they vary, what factors drive this variation, and how these factors play out in different regions has received little attention in the broader CCS community, as well as with application to integrated assessment modeling.

The central research question is whether, and to what degree, the costs of CO_2 transport and storage can be captured in more detail than is currently used in integrated assessment models, but not as so detailed a level as to be practically or computationally burdensome. The objectives of this thesis are to (1) consider different options for CO_2 transportation (pipelines, shipping, etc.), storage (saline aquifers, depleted oil and gas fields, etc.), and project networks (clustering); (2) assess the range of costs for these various CO_2 transport and storage options in different regions of the world; and (3) evaluate the impact of the range of transport and storage costs on economy-wide modelling results of decarbonization pathways that include the CCS option.

To address my objectives, first I conducted a literature review of recent studies that evaluate the cost of different CO_2 transport and storage technologies. This included reviewing key bottom-up modeling approaches for estimating the cost of CO_2 transport and storage separately and identifying which approaches to use in my analysis. I quantified transport and storage costs separately using my chosen modeling approaches and combined these into a single cost range. As part of this effort, I quantified five key sources of variability and uncertainty impacting transport and storage costs. Next, I incorporated my estimated transport and storage cost range into MIT's Economic Projection and Policy Analysis (EPPA) model. Using EPPA, I explored the impact of variability in transport and storage costs by applying a range of uniform transport and storage costs in all regions in a future where global temperature rise is limited to 2°C. Then, I examined several cases in which transport and storage costs vary regionally. This top-down portion of my analysis allowed me to evaluate the impact of variable transport and storage costs on economy-wide modeling results of climate pathways that include the CCS option.

This thesis is divided into two parts. In Part I, I describe my bottom-up approach to quantifying the range of transport and storage costs. Chapter 2 provides a background of the key cost components underlying different CO_2 transport and storage methods as well as a summary of the literature review. In Chapters 3 and 4, I describe different technology options, the current status of, and methods I used to quantify CO_2 transport and CO_2 storage costs respectively. Part I concludes with Chapter 5 where I present a combined CO_2 transport and storage cost range and quantify the magnitude of the five key sources of variability and uncertainty underpinning this range.

In Part II, I explain how I incorporated my transport and storage cost range from Part I into MIT's EPPA model as part of a top-down modeling analysis of decarbonization pathways that include the CCS option. Chapter 6 provides background on integrated assessment modeling as an analytical approach. Chapter 7 outlines the results from modeling cases in which I applied a range of transport and storage costs that are uniform in all geographic regions. Chapter 8 describes the methodology I used to construct my Base Case in which transport and storage costs vary regionally, and Chapter 9 outlines select regional sensitivities.

Chapter 10 summarizes key takeaways from Parts I and II and identifies areas where further analysis is needed. This chapter also identifies the key policy-relevant information for decision makers.

PART I: Quantifying CO_2 Transport and Storage Cost Range

2. Background on CO_2 Transport and Storage Cost Estimates

2.1. Literature Review

2.1.1. Background on CO_2 Transport and Storage in CCS Cost Analyses

One of the most impactful cost analyses related to CO_2 transport and storage published in recent years is Rubin et al. (2015), which summarized CO_2 transport and storage costs from several key studies published between 2000 and 2015 and adjusted these estimates to a common basis for accurate comparison (IPCC, 2005; ZEP, 2011a; ZEP 2011b; GCCSI, 2011; USDOE, 2014a; USDOE, 2014b). For this thesis, I performed two literature reviews for studies published after 2015 - one focused on CO_2 transport and one focused on CO_2 storage. I used search terms broad enough to include studies that combined transport and storage costs into a single estimate as well as papers that estimated transport and storage costs separately. I compiled papers published in academic journals as well as studies from governments, industry groups, and international governing bodies. In this section, I provide high-level insights on the state of CO_2 transport and storage cost estimates in the literature broadly and provide more detail on the transport- and storage-specific takeaways in the next two sections.

Rubin et al. (2015) stressed the challenge of comparing CCS cost estimates across studies because of inconsistent documentation of key metrics and underlying assumptions. After reviewing the literature published after 2015, I conclude there is still a great deal of variability and ambiguity in documentation of key CO_2 transport and storage cost metrics, which continues to make comparison across studies difficult. Different studies vary in their treatment and reporting of inflation rates and whether costs are reported in constant or current dollars (which exclude or include the effects of inflation, respectively). There is also variation in the year of currency used, and it is not always transparent what method or index is used to escalate costs to a particular year. Moreover, transport and storage costs are typically reported using one of several common metrics, each of which measures something different. Common metrics include: i) cost of CO_2 avoided ($/t$CO_2$), which includes the total cost of CO_2 captured and stored and can only be reported as part of a complete CCS system; ii) levelized cost of transport or storage (\$/tCO_2), which measures the cost of transport or storage amortized over the life of a project; and iii) unitary transport cost per unit of distance or quantity transported.

Many studies also obscure the system boundary between CO_2 capture and transport, and between CO_2 transport and storage. This makes it difficult to accurately assess the magnitude of transport and storage costs individually. For instance, CO_2 conditioning is required to compress CO_2 prior to pipeline transport and studies vary in whether CO_2 conditioning is included as part of the capture or transport cost, and some studies do not distinguish this at all. There are also several important project assumptions – such as overall CO_2 quantity being transported or stored, time horizon of the project, utilization rate of the transport or storage infrastructure, etc. - that can have a sizeable impact on cost estimates, but which are inconsistently documented across the literature. Finally, there is regional variation in the cost of capital, labor, materials, and other inputs that impact transport and storage cost assessments documented in a particular geography, as well as different regulatory structures incentivizing or disincentivizing parts of the CCS value chain.

Awareness of the above factors is critical for accurate comparison of CO_2 transport and storage costs across studies, though it is important to remember that different studies report CCS cost estimates with different objectives, scopes, and audiences in mind. Since there is often a tradeoff in detail vs. scope in many modelling analyses, it is important to identify the central question or objective in order to identify the appropriate analytical tool and interpret results accordingly. Bottom-up studies in the literature tend to report transport and storage costs tailored to a particular project or geography and are often focused on generating accurate, detailed cost estimates for a specific CCS scheme in a given region. By contrast, top-down studies typically seek to capture large-scale macroeconomic trends broadly to inform policy and decisionmakers. These are typically the type of studies that employ IAMs or other macroeconomic models as analytical tools. My objectives are to characterize CO_2 transport and storage costs in more detail than is currently assumed in many studies and often estimated at \$10/tCO_2 in order to better understand future decarbonization pathways that include CCS and the policy implications they present (IPCC, 2014; Rubin et al., 2015; IEAGHG, 2017; Morris et al., 2019).

2.1.2. CO_2 Transport

The key questions guiding my CO_2 transport literature review are as follows: can the cost of CO_2 transport be broken down in more granular detail based on specific factors, such as the method of transport, region, source of CO_2, destination of CO_2, project networks, and other factors? How do studies published since 2015 attempt to calculate CO_2 transport costs, what models are they using, and what metrics are they reporting? What are the key cost components related to CO_2 transport and what assumptions are made about them? I focused on studies published after 2015 because Rubin et al. (2015) summarized and adjusted to a common basis many of the key CO_2 transport and storage cost studies published between 2000 and 2015.

After reviewing the literature, several key themes emerged. With regard to transport method, CO_2 pipelines are still the main transport option modeled in the literature (IEA, 2020; Abramson et al., 2020; NPC, 2019; Zapantis et al., 2019; Yu et al., 2019; Budinis et al., 2018; USDOE, 2018; Grant et al., 2017; Jakobsen et al., 2017; Selosse & Ricci, 2017; Skaugen et al., 2016; Wei, et al. 2016). A large number of studies also explore ship transport, which can be a cost-effective option for offshore CO_2 storage depending on the volume of CO_2 and distance transported (IEA, 2020; d'Amore & Bezzo, 2017; Jakobsen et al., 2017; Neele et al., 2017; Kjarstad et al., 2016; Knoope et al., 2015). Many of these studies were focused on bottom-up cost analyses for ship transport schemes in Europe, particularly given ongoing projects that are actively injecting CO_2 for permanent storage in the North Sea. Several studies explored truck and rail transport (Sanchez et al., 2018; Psarras et al., 2020). Rail and truck transport typically involve small volumes of CO_2. However, most analyses indicate that to deploy CCS at the scale required to achieve global climate goals, pipelines, ships, and project networks capable of transporting megatons of CO_2 are likely necessary, not to mention much lower cost (Friedmann et al., 2020). As such, I do not focus on truck or rail transport in my analysis.

Several CO_2 transport cost studies explored the spillover costs at the boundary between CO_2 capture and transport, and between CO_2 transport and storage. One way this can play out is through impurities in the CO_2 stream, which risk eroding pipelines and storage tanks if not removed prior to transport (Weiland et al., 2017; Skaugen et al., 2016). The level and type of impurities depend on the CO_2 source and type of capture equipment, which in turn impact the extra purification cost. When taking these costs into account, studies differ in whether costs are added as part of the capture or transport cost. Relatedly, a theme emerged about the ways that uncertainty about storage reservoir quality can impact transport costs, even after site characterization. Transport costs can increase significantly if a reservoir doesn't perform as expected and the CO_2 must be re-routed for storage elsewhere (Middleton & Yaw, 2018; Kjarstad et al., 2016). By contrast, lower-than-expected storage costs can in some cases justify transporting CO_2 longer distances. Some studies suggested that fluctuations in CO_2 transport costs tend to impact the choice of a reservoir rather than the deployment of CCS broadly.

Many of the papers I reviewed were bottom-up analyses focused on evaluating CO_2 transport costs for a particular region or project scheme. These studies tended to employ modeling approaches or methods that fell into one of several categories, including: 1) source-sink matching (Yu et al., 2019; Sanchez et al., 2018; Selosse & Ricci, 2017; Grant et al., 2018); 2) regional techno-economic analysis (Jakobsen et al., 2017; Skaugen et al., 2016); 3) cash-flow models (Neele et al., 2016); or 4) a combination of the above methods (USDOE, 2018). Notably, several U.S.-based studies used the USDOE (2018) CO_2 transport cost model to quantify transport costs via pipeline for use in their analysis (Abramson et al., 2020; NPC, 2019). I considered the strengths and limitations of each of these approaches when choosing a method for quantifying CO_2 transport costs in my own analysis, which I discuss in the subsequent sections.

2.1.3. CO_2 Storage

The key questions guiding my CO_2 storage literature review are as follows: can the cost of CO_2 storage be broken down in more granular detail based on specific factors, such as the type of reservoir, region, source of CO_2, project networks such as clusters and hubs, regulatory requirements such as monitoring costs, and other factors? How do studies published since Rubin et al. (2015) attempt to calculate CO_2 storage costs, what models are they using, and what metrics are they reporting? What are the key cost components related to CO_2 storage and what assumptions are made about them?

In terms of reservoir type, most studies estimate the cost to store CO_2 in onshore and offshore saline aquifers or depleted oil and gas fields (IEA, 2020; Anderson et al., 2019; NPC, 2019; Van der Spek et al., 2019; Budinis et al., 2018; IEAGHG, 2018; Anderson et al., 2017; Grant et al., 2017; USDOE, 2017; Pale Blue Dot, 2016). Some studies report cost projections for other types of storage reservoirs such as shale, offshore sedimentary, and basalt formations, but most of these sites are in the early stages of research and development and are not considered technically mature (US EPA, 2018; Gunnarsson et al., 2018; Snæbjörnsdóttir & Gislason, 2016).

With regard to saline aquifers, many studies do not consider pressure management, which presents a tradeoff between CO_2 storage capacity and cost (Anderson et al., 2017). The degree to which pressure builds up varies by region and is particularly an issue for closed geologic reservoirs where CO_2 cannot migrate freely underground. With regard to depleted oil and gas reservoirs, many analyses have attempted to quantify the potential cost savings of re-using legacy infrastructure, but there is still a fair amount of uncertainty about whether the time and cost of verifying infrastructure integrity would reduce or increase CO_2 storage costs relative to saline aquifers (Pale Blue Dot, 2016; NPC, 2019). In both geologic settings, however, economies of scale associated with the clustering of CO_2 storage hubs is expected to lower storage costs (IEA, 2020; NPC, 2019; Pale Blue Dot, 2016).

Differences in regulatory regimes and institutional settings can affect the cost of CO_2 storage and studies differ in their treatment of ongoing and anticipated policy developments. In some regions, there is public resistance to onshore CO_2 storage due to concerns about induced seismicity or concerns about the permanence of geologic CO_2 storage due to leakage. Regions differ in how they address these concerns through policy and by extension, studies differ in how they capture the costs or savings associated with a constantly shifting policy landscape. Some regions have favorable regulatory environments that reduce the cost of CO_2 storage, such as through the presence of tax credits and exemptions, access to loans or capital, ability to access, re-use, or hare nearby oil and gas infrastructure, and other policy mechanisms. Other regimes have policies that may increase CO_2 storage costs directly, such as strong liability or measurement, monitoring, and verification (MMV) requirements, different tax rates, or other regulatory structures (USDOE, 2017). Uncertainty about future policy developments also impact CO_2 storage costs may delay CCS deployment. In the United States, for example, key sources of regulatory uncertainty have included the IRS's delay in publishing guidance on the 45Q tax credit, opacity on how existing mineral rights laws will treat CO_2 royalty payments, and interaction of federal and state laws (Zapantis et al., 2019).

2.2. Uncertainty and Variability in Key Cost Components and Parameters

This section breaks down the primary cost components and their underlying parameters for CO_2 transport and storage. The cost components visible in Figure 1 are derived from the CO_2 Transport Cost Model (US DOE, 2018) and CO_2 Saline Storage Cost Model (USDOE, 2017) operated by the U.S. Department of Energy's National Energy and Technology Laboratory (NETL). These cost components reflect onshore CO_2 pipeline transport and storage in saline aquifers (depleted oil and gas fields have effectively the same cost components). In my analysis, the system boundary begins at the point CO_2 enters the pipeline or ship for transport - CO_2 conditioning is incorporated into the CO_2 capture cost and is not included in my analysis.

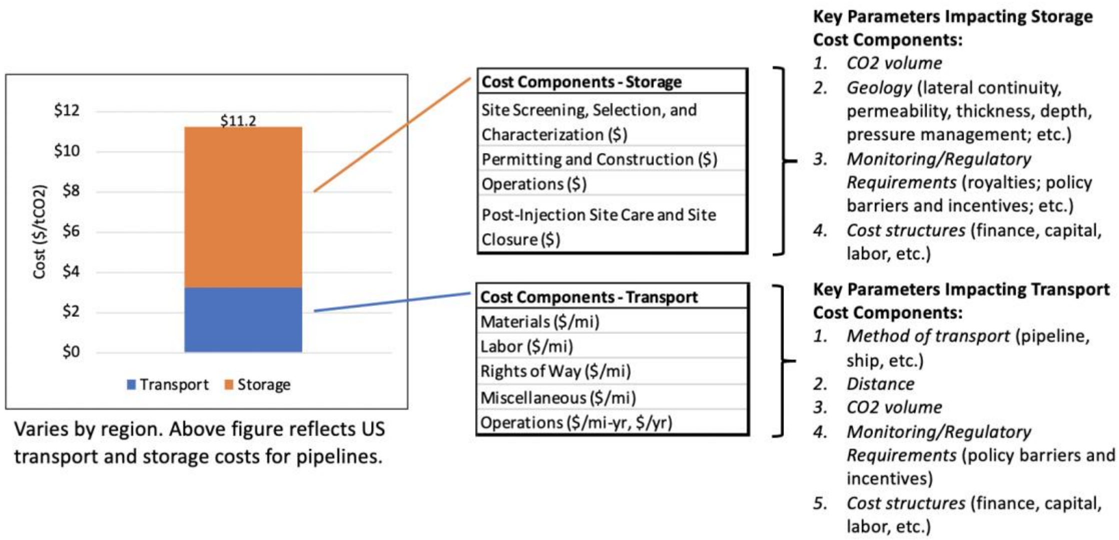

Figure 1. Summary of CO_2 Transport and Storage Cost Components and Parameters. These costs represent the U.S. average cost for transport via onshore pipeline and storage. Costs will vary by region and transport and storage method.

Data for CO_2 pipeline costs is limited but natural gas pipelines are a useful analog by which to understand the underlying cost components, which broadly include capital and operations expenses. Capital expenditures include pipeline construction materials, labor, rights of way, and miscellaneous costs related to executing site surveys, engineering, supervision, contingencies, taxes, administration, etc. Operations expenditures include fixed and variable costs associated with pipeline maintenance and related equipment including booster stations, the pipeline control system, electricity consumption, and other related costs. Transport costs generally decline with larger CO_2 volumes due to economies of scale. The degree to which various pipeline capital cost components decline for longer pipeline distances or larger CO_2 volumes varies and depends underlying calculation method. Regulatory barriers and incentives and different cost structures can impact all of the transport-related cost components depicted in Figure 1.

The CO_2 storage cost components listed in Figure 1 are grouped into four typical project stages, which include site selection and characterization, permitting and construction, operations, and post-injection site care (PISC) and closure. A variety of costs are incurred across these four project stages, including data acquisition; permitting; fees, lease, and pore space fees; reporting; monitoring activities such as 3D seismic surveys and above ground monitoring; well drilling and installation; data collection and analysis of well performance; well plugging; corrective action; and other miscellaneous costs. The cost of drilling wells – which include exploration, injection, and monitoring wells - is one of the most expensive components of a storage project. The number of required CO_2 injection wells depends on a handful of key geologic parameters listed in Figure 1. Meanwhile, the number of monitoring wells largely depends on the stringency of a given regulatory regime. Some institutional settings may demand a high ratio of monitoring to injection wells, liability insurance, and a long duration of post injection site care, which can increase overall storage costs. In general, storage costs exhibit economies of scale with increasing CO_2 volume.

3. CO_2 Transport Costs

3.1. CO_2 Transport Options

3.1.1. Pipelines

CO_2 pipelines are a mature technology and have been widely used globally for decades, with over 5,000 miles of CO_2 pipelines in the United States in 2017 (Righetti, 2017). CO_2 pipelines in the United States are used primarily to transport CO_2 to oil fields for use in enhanced oil recovery. As mentioned, data for the cost of transporting different quantities of CO_2 are limited, but natural gas pipelines are a useful analog by which to understand the cost components and variability underpinning CO_2 pipelines. Both depend largely on pipeline diameter and distance and differ little in land construction costs, though CO_2 pipelines may cost slightly more due to greater pipe thickness needed to transport CO_2 at higher pressure (Heddle, 2003). The feasibility of repurposing natural gas pipelines for CO_2 transport is not practical for transporting large quantities of CO_2 (e.g., 20 Mtpa) over long distances (100 miles or more). This is because CO_2 requires a higher pressure than natural gas to be kept in a liquid state for pipeline transport, and thus thicker pipelines are generally needed (NPC, 2019). Offshore pipelines exhibit many of the same cost components and variability as onshore pipelines but tend to be more expensive due to the more complicated offshore equipment required for construction on the ocean floor.

3.1.2. Shipping

Shipping is a mature technology for liquefied natural gas (LNG) and liquefied petroleum gas (LPG) but is not widely used for CO_2 transport today. LPG tankers are a closer analog for CO_2 transport via ship than LNG tankers because liquefied CO_2 must be transported at elevated pressures like LPG, whereas LNG is transported at atmospheric pressure. LPG tankers can be repurposed for

CO_2 or dual-purpose transport, but in general, tankers specifically designed for CO_2 transport can be better optimized for maximum capacity and investment cost (IEAGHG, 2020).

3.1.3. Rail and Truck

CO_2 can be transported via train or truck and may be economic over short distances and small CO_2 quantities (Sanchez et al., 2018; Psarras et al., 2020). While rail and truck transport may be important for small-scale transport in the early years of CCS expansion, it is not expected to play a major role in large-scale rollout of CCS. Pipelines and ships are expected to be much more cost effective in transporting megatons of CO_2 per year (Mtpa) due to economies of scale (NPC, 2019).

3.2. Current Status of CO_2 Transport Costs

CO_2 transport costs vary due to transport method (i.e. pipelines vs. ships); whether CO_2 is transported onshore or offshore; scale (quantity of CO_2 transported); distance to CO_2 storage; monitoring and regulatory requirements including policy barriers and incentives; cost structures related to financing, capital, and labor; and the CO_2 source and whether or to what degree it is pressurized or purified prior to transport. All of these variables vary across regions due to differences in geology, geography, and institutional settings. Pipelines are generally the most cost-effective CO_2 transport option in most regions, though shipping can be cost effective for transporting CO_2 over long distances.

Shared CO_2 transport networks have significant potential to reduce costs through economies of scale (Pale Blue Dot, 2016; Friedmann et al., 2020). The cost and feasibility of CO_2 transport networks varies regionally and is interdependent with the development of CO_2 source clusters and storage hubs. There are several promising locations for CCS clusters and hubs globally that are being pursued that could facilitate a shared transport infrastructure, particularly in the United States, Europe, and China (IEA, 2020). In the United States, much analytic work has been dedicated to exploring potential trunk line networks and routes in the U.S. midcontinent and gulf coast, in addition to movement on federal legislation that would fast-track permitting for CO_2 pipelines (Abramson et al., 2020). Relatedly, in October 2019 amendments to the London Protocol were ratified by a sufficient number of participating parties that would allow cross-border transport of CO_2 in Europe, which previously had faced regulatory hurdles (IEAGHG, 2020).

Several regions are investigating CO_2 shipping for future scaled-up CCS operations, most notably the Northern Lights Project in Europe and JGC Corporation in Japan. The Northern Lights Project initially expects to transport up to 1.5 Mtpa CO_2 captured from two industrial plants in Norway by ship to temporary onshore storage, after which it will be transported by offshore pipeline for permanent storage in geologic formations in the North Sea. Eventually, the project envisions transporting CO_2 by ship from CCS hubs across Europe, with a targeted scale of 5 Mtpa CO_2 by 2030. In Japan, most CO_2 storage reservoirs are offshore and the JGC Corporation is wrapped up its demonstration phase for offshore CO_2 transport and storage in 2020, with projections to reuse existing offshore oil and gas infrastructure (JGC, 2019).

Because shipping is not widely used for CO_2 transport today, I relied on published estimates of shipping costs for my analysis. IEAGHG (2020) estimates CO_2 shipping costs for four scenarios in Europe and reports a similar cost range as the Northern Lights Project. However, these estimates do not include the cost of CO_2 injection, leaving a degree of uncertainty with regard to the total cost. For this reason, I assume shipping costs reported by Northern Lights Project, which has a targeted combined cost range of €30-55/tCO_2 for CO_2 transport and storage by 2030 (Northern Lights Project, 2020).

3.3. CO_2 Transport Cost Range

This section explains my method for calculating the CO_2 transport cost range for onshore CO_2 pipelines in the United States and how this range can be used to estimate costs for offshore pipelines and pipeline networks. For my analysis, I assume a pure stream of CO_2 that is compressed prior to transport. There are three key sources of variability in CO_2 transport cost estimates: 1) distance, 2) scale (i.e., quantity of CO_2 transported), and 3) underlying transport cost assumptions, particularly pipeline capital costs.

To explore the variability in CO_2 pipeline costs I used a variety of models, most notably Heddle et al. (2003), the NETL CO_2 Transport Cost Model (USDOE, 2018), and NPC (2019). USDOE (2018) is an open-source Excel model that combines elements of techno-economic and cash-flow analysis to estimate the cost of transporting CO_2 in the United States for an onshore point-to-point pipeline. NPC (2019) used a modified version of the USDOE (2018) model and provided Excel-based documentation laying out their key assumptions and cash flow analysis for transporting and storing CO_2 in key U.S. regions. Heddle et al. (2003) employs a pipeline capital cost factor in dollars per inch per mile and provides an Excel-based model for users to calculate the cost to transport CO_2 under different criteria. The inch refers to pipeline diameter and the mile refers to pipeline length. Pipeline construction costs include materials, labor, rights of way, and other miscellaneous costs (e.g. surveys, engineering, supervision, contingencies, etc.). CO_2 pipelines have been a mature technology for decades and after comparison with recent models like USDOE (2018) – which references Heddle et al. (2003) in its approach and also uses capital cost factors - I concluded Heddle et al. (2003)'s method to be simple, accurate, and consistent in estimating CO_2 transport costs in dollars per ton ($/t$CO_2$) for a given CO_2 flow rate and distance.

Heddle et al. (2003) used natural gas pipelines as an analog for estimating the cost of CO_2 transport via pipeline. Both face similar construction costs that are sensitive to distance and scale, though CO_2 pipelines may cost slightly more due to greater pipeline thickness needed for transporting CO_2 at higher pressures. Heddle et al. (2003) leveraged industry data on natural gas pipelines from 1989 to 1998 to chart the relationship between average CO_2 pipeline construction cost (in $/mile) as a function of CO_2 flow rate (Figure 3). Pipeline diameter depends on the CO_2 flow rate (Figure 2), so I was able to translate this into a relationship of average CO_2 pipeline construction cost (in $/mile) versus pipeline diameter.

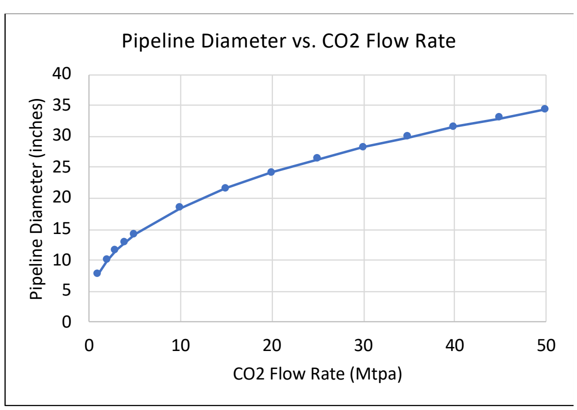

Figure 2. Pipeline Diameter as a function of CO_2 Flow Rate.

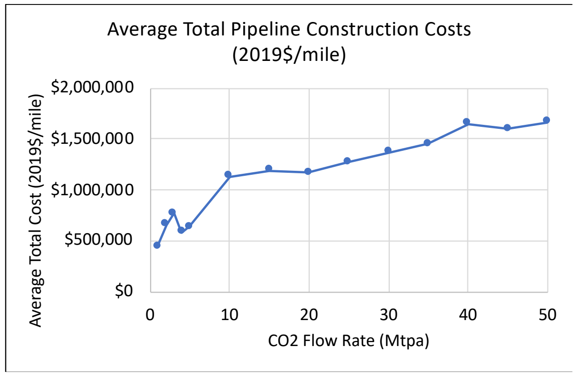

Figure 3. Average pipeline construction costs in 2019$/mile as a function of CO_2 Flow Rate.

I escalated costs from Heddle et al. (2003) to current 2019 dollars according to the Producer Price Index (PPI) normalized to 100 in the year 2000 (U.S. Bureau of Labor Statistics, 2020). Rubin et al. (2015) escalated transport and storage costs according to the Chemical Engineering Plant Cost Index (CEPCI) because these services are typically provided to power plants by organizations from the oil and gas industry. I compared several cost indices and opted to use the PPI because it tracked closely with CEPCI, which is no longer open source for data from recent years (Figure 4).

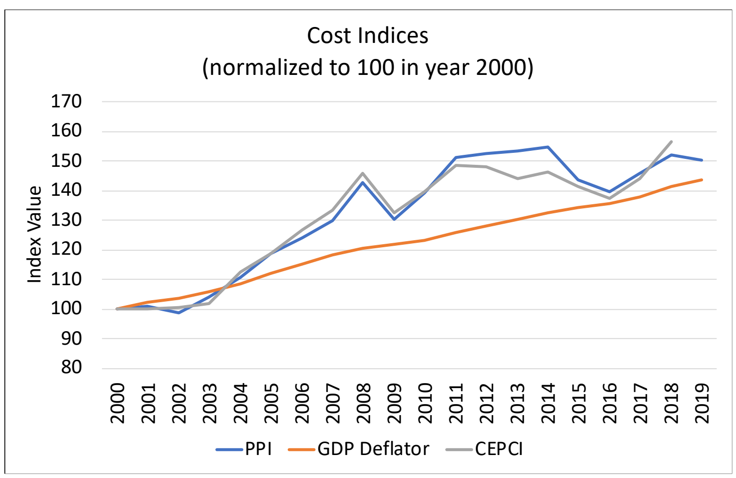

Figure 4. Comparison of Cost Indices for Price Escalation.
For this analysis, PPI was used to escalate costs.

After escalating costs, I then followed Heddle's approach by using linear regression on mean pipeline construction costs (in $/mile) for a given pipeline diameter to calculate a capital cost factor of $52,892/in-mi for onshore CO_2 pipelines. I then built low and high capital cost factor estimates by using linear regression on pipeline construction costs (in $/mile) for a given pipeline diameter two standard deviations above and below the mean, yielding a range of \$18,195/in-mi to \$87,588/in-mi reported in Table 1.

These capital cost factors include pipeline construction costs only - O&M costs were added separately as an O&M cost factor in dollars per year per mile (\$/yr/mi). USDOE (2018) used O&M cost factors from Heddle et al. (2003). Finally, following Heddle et al. (2003)'s approach, I annualized construction costs using a capital charge rate of 15% per year and added this to the annual O&M cost. From there I were able to estimate the total cost of transporting any CO_2 quantity any distance (Figure 5).

Table 1. Capital cost factor range for onshore CO_2 pipelines in current 2019\$/in-mi

Source	Low	Mean	High
Heddle (2003)	\$18,195	\$52,892	\$87,588
USDOE (2018)	\$40,052	\$51,581	\$83,881
NPC (2019)	\$80,000	\$115,000	\$150,000

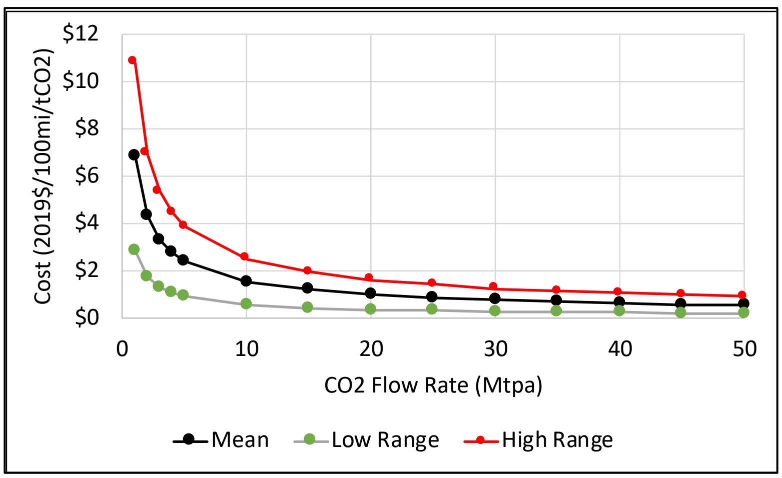

Figure 5. Total CO_2 transport costs for a 100-mile onshore pipeline in the United States in 2019 current dollars.
Low and high cost range reflect two standard deviations away from the mean and are based on the capital cost factors updated from Heddle (2003) as visible in Table 1.

USDOE (2018) documents mean and high capital cost factors similar to the range I calculated using Heddle et al. (2003)'s approach. USDOE (2018) low, mean, and high values in Table 1 reflect capital cost factors based on a 100 mile 12-inch diameter pipeline and are calculated using three equations from Rui, McCoy, and Parker, respectively. All three equations use pipeline capital costs reported in O&GJ (1989), encompass the same cost components outlined in Figure 1, and calculate capital cost factors as a function of pipeline length and diameter. Grant et al. (2017) used Parker's equation (which corresponds to the high estimate listed in Table 1 for USDOE (2018)) to be conservative and err on the side of over-estimating CO_2 transport costs. NPC (2019) documents higher capital cost factors ranging from $80,000/in-mi to $150,000/in-mi across four major U.S. regions. Their mean value in Table 1 reflects the midpoint of this range. However, NPC (2019) estimates a cost of $100,000/in-mi for three likely trunk line routes in the United States. My calculated mean and high capital cost factors of $52,892 and $87,588, respectively, are similar to the mean and high capital cost factors documented in USDOE (2018) and those of likely U.S. trunk line routes reported in NPC (2019).

Offshore pipelines exhibit many of the same cost components and variability as onshore pipelines but tend to be more expensive. By contrast, pipeline networks are generally assumed to be less expensive due to infrastructure sharing and economies of scale. For simplicity, I assume multipliers of onshore pipeline costs to estimate higher-cost offshore pipelines and lower-cost pipeline networks based on figures reported in the literature. Some studies suggest offshore pipelines can cost 50 to 100% more than onshore pipelines (CO_2Europipe, 2011) while pipeline networks can reduce costs up to 75% (Zapantis et al., 2019).

Shipping is not widely employed today for CO_2 transport but is seriously being considered for future use as CCS scales up in Europe and Japan. I assume shipping costs based on current figures from the Northern Lights Project, which targets CO_2 transport and storage costs of 30 to 55€/tCO_2 ($35 to $64/t$CO_2$ USD) by 2030 for 5 Mtpa CO_2.

4. CO_2 Storage Costs

4.1. CO_2 Storage Options

4.1.1. Saline Aquifers and Depleted Oil and Gas Fields

The vast majority of CO_2 storage potential worldwide is in onshore and offshore saline aquifers (USGS, 2013). The cost of CO_2 storage is very site dependent because geologic characteristics vary from site to site and injection, labor, drilling, capital, and other costs vary regionally. Similar to offshore pipelines, offshore CO_2 storage is generally more expensive than onshore storage. For CO_2 storage in saline aquifers, various types of wells must be drilled (exploration, injection, and monitoring) which comprise a large share of the overall storage cost. The number of wells that must be drilled hinges on the scale of the project and a handful of key geologic parameters discussed in the next section. In addition, many published CO_2 storage cost estimates of saline aquifers do not consider the cost of extracting, processing, and disposing of formation fluid to make way for injected CO_2, which is particularly an issue in closed onshore saline formations (Anderson et al., 2019). Such closed formations that require active pressure management present a tradeoff between CO_2 storage capacity and storage cost.

The same geologic parameters that shape the number of wells that must be drilled to inject a given quantity of CO_2 in saline aquifers also impact depleted oil and gas fields. Previous studies have suggested the cost of CO_2 storage in depleted oil and gas fields is lower than in saline aquifers because the oil and gas fields have already been surveyed and offer the potential to reuse existing infrastructure (ZEP, 2011a). However, uncertainty and costs associated with verifying infrastructure integrity and repurposing it for CCS applications may negate any cost savings, or it can increase the risk of CO_2 leakage through existing wells and thus require more monitoring, which also raises costs. These competing factors prevent us from distinguishing the difference in storage costs between saline aquifers and depleted oil and gas fields; therefore, in this study I approximate them as being the same.

4.1.2. Other Storage Reservoirs

Other geologic formations have potential to store CO_2. Unmineable coal seams have been investigated, but many questions still remain about whether they are a practical storage medium.

Formations that are in the early stage of study include shale formations, basalt formations where CO_2 crystallizes into solid carbonate minerals (e.g., active project in Iceland (Gunnarsson et al., 2018)), and shallow offshore sedimentary formations. These alternative storage formations are outside the scope of this study.

4.2. Current Status of CO_2 Storage Costs

CO_2 storage costs hinge on three major sources of variability: 1) geologic characteristics; 2) scale (i.e., amount of CO_2 stored); and 3) monitoring, financial, and other modeling assumptions. A handful of geologic parameters are primary determinants of whether a reservoir is favorable for CO_2 storage: permeability, thickness, depth, porosity, and lateral continuity (USDOE, 2014a; USDOE, 2017). These features dictate how much total CO_2 can be stored in a reservoir, the number of wells that must be drilled, and the degree to which pressure buildup must be managed, which adds extra costs. Some estimates suggest the cost of pressure management could double CO_2 storage costs (Anderson, 2017). Reservoirs with the lowest storage costs are permeable and thick, while reservoir depth can impact the cost of drilling injection and monitoring wells. The cost to drill injection and monitoring wells varies regionally and CO_2 storage costs are quite sensitive to assumptions around the number of injection and monitoring wells required.

Regulatory regimes and financial assumptions also impact the cost of CO_2 storage. In the United States, the 2018 expansion of the 45Q tax credit is expected to stimulate billions of dollars of investment in CCS by providing financial incentives for CO_2 stored permanently in saline reservoirs or via enhanced oil recovery (Bennett and Stanley, 2018). Different jurisdictions have different requirements regarding long-term liability of CO_2 storage and how long secure geologic storage must be monitored; for example, United States federal and California state protocols differ. This has the potential to raise storage costs and is not modeled in many studies, with the 2017 NETL CO_2 Saline Storage Cost Model (USDOE, 2017) being a notable exception. Relatedly, just as U.S. landowners receive royalty payments for oil and gas produced on their property, in the presence of a price on carbon or other CO_2 storage tax credits, it is unclear if or how royalty payments on stored CO_2 would be implemented and how this might impact CO_2 storage costs.

CO_2 storage costs typically decline as the scale of a storage project increases. As CCS deployment ramps up, CCS hubs - which are industrial centers that leverage a shared CO_2 transport and storage infrastructure – are expected to develop and reduce CO_2 transport and storage costs through economies of scale. Since 2017, investment plans have been announced for several potential CCS hubs, including five in the United States, four in China, and 12 across Europe (IEA, 2020). These dynamics are important to keep in mind when representing CO_2 storage costs in energy economic models and understanding their impact on decarbonization pathways.

4.3. CO_2 Storage Cost Range

This section explains my method for calculating CO_2 storage costs for saline aquifers and depleted oil and gas fields in the United States. As discussed in the previous section, I assume storage costs are the same for saline aquifers and depleted oil and gas fields.

There are three key sources of variability in CO_2 storage cost estimates: 1) geologic characteristics, 2) scale, and 3) model assumptions regarding monitoring, finance, etc. Permeability, thickness, depth, porosity, and lateral continuity are among the geologic features most impactful in determining reservoir suitability for CO_2 storage. These parameters determine the total volume of CO_2 that can be injected into a reservoir (a matter of scale) as well as the maximum rate of CO_2 injection per injection well which, by extension, determines the number of injection wells required. In general, thick, permeable formations are optimal because they can store more total CO_2 and require fewer injection wells. Some studies including NPC (2019) assume a certain ratio of monitoring wells per injection well, as well as assumptions about finance costs. I explored several models with various strengths and limitations in capturing these key sources of variability.

- **Heddle et al. (2003).** Heddle's model captures several geologic parameters in great detail including their impact on CO_2 injection rate per well and required number of injection wells. However, the costs underpinning this model reflect outdated drilling technology that I concluded was not suitable for my analysis.

- **IECM (2015)**. IECM is an open source model maintained by Carnegie Mellon University under contract to the US Department of Energy that allows users to adjust a variety of geologic parameters and modeling assumptions for various regions in the United States to calculate an overall cost of CO_2 storage.
- **USDOE (2017)**. NETL manages the CO_2 Saline Storage Cost Model, a large, open source model with detailed geologic monitoring capabilities that was last updated in 2017. Grant et al. (2017) used this model to report CO_2 storage costs for 4 U.S. formations with a range of geologic properties. By default, USDOE (2017) assumes a flat cap on the CO_2 injection rate per well and rigorous monitoring requirements. For these reasons, I believe this model reports estimates on the high end of the CO_2 storage cost range.
- **NPC (2019).** Uses a modified version of USDOE (2017) that reduces the ratio of monitoring wells per injection well, reduces the number of 3D seismic studies, and focuses on the lowest cost (<$15-20/t depending on region) storage formations. The study calculated CO_2 storage costs using volume-weighted averages across several U.S. regions, reporting a national average CO_2 storage cost of $8/t$CO_2$.

For my analysis, I used a modified version of USDOE (2017) in line with NPC (2019) assumptions because 1) the USDOE (2017) and IECM (2015) models were similar in methodology and produced similar estimates of storage cost and number of injection and monitoring wells, and 2) to be consistent with NPC (2019), which I assess to be the most accurate reported estimate of CO_2 storage costs, as well as the most recent. Below, I outline my approach to quantifying the three key elements of variability in CO_2 storage costs.

I selected 13 U.S. reservoirs with a range of reservoir properties to serve as a proxy for geologic variability that storage project developers are likely to encounter globally (Table 2). Eleven of these reservoirs are from Szulczewski et al. (2013) and two from the Grant et al. (2017). These reservoirs have a combined CO_2 storage capacity of 360 Gt out of an estimated 500 to 4,000 Gt of onshore storage capacity in the United States (Kearns et al. 2017). I used permeability, thickness, and depth values reported in Szulczewski et al. (2013) and Grant et al. (2017). For reservoir pressure I assumed hydrostatic pressure, which is a function of depth. The rest of the parameters were from the USDOE (2017) database. Where a particular reservoir was not included in the USDOE (2017) database, I used the closest analog in the same basin or region. The reservoirs in Table 2 are ranked in order from most to least favorable as determined by the product of permeability and thickness.

Table 2. Reservoir Properties from Szulczewski et al. (2013) and Grant et al. (2017).

Formation	Permeability (mD) * Thickness (m)	Depth (m)	Mean Storage Capacity (Gt CO_2)	Storage Capacity Standard Deviation (Gt CO_2)
Potomac	1,200,000	1,000	4	2
Frio	800,000	1,000	18	8
Woodbine*	106,680	1,676	24	
Black Warrior River	100,000	1,000	31	12
Mt. Simon	40,000	2,000	88	27
Madison	36,000	3,000	5	2
Fox Hills	20,000	1,000	6	2
Navajo-Nugget	20,000	3,000	5	2
Morrison	14,000	2,000	17	5
Red River*	6,300	2,743	72	
Paluxy	4,500	2,000	2	0.5
Cedar Keys	4,000	2,000	87	22

*Data from Grant et al. (2017), which does not report a standard deviation for storage capacity.

Using the USDOE (2017) model with the parameter values described above, I calculated the CO_2 storage cost for all 13 reservoirs in Table 2 for four different scales of CO_2 transport and storage projects (in Mtpa) to reflect varying levels of CCS deployment.

- 1 Mtpa - roughly equivalent to one demonstration-scale CO_2 transport and storage project.
- 3.2 Mtpa – reflects a handful of CO_2 transport and storage projects and is the same scale used in Grant et al. (2017) and NPC (2019).
- 6 Mtpa - reflects moderate levels of CCS deployment and is roughly twice the level assumed in Grant et al. (2017) and NPC (2019), and is slightly higher than the Northern Lights Project target of 5 Mtpa CO_2.
- 15 Mtpa - reflects large-scale rollout of CCS encompassing numerous CO_2 clusters, hubs, and shared transport networks globally.

One quirk of the USDOE (2017) model is that it capped cumulative CO_2 injected into each reservoir at levels significantly below 15 Mtpa CO_2. As a result, I extrapolated my storage costs for 15 Mtpa by calculating the cost difference per $MtCO_2$ between 1 and 3.2 Mtpa CO_2, and 3.2 and 6 Mtpa CO_2, to approximate a rate of cost decline with scale for each reservoir. I applied this rate of cost decline to estimate CO_2 storage costs for 15 Mtpa CO_2.

By default, USDOE (2017) assumes stringent monitoring requirements that I determined to reflect the high end of the CO_2 storage cost range and which I refer to as "extra" monitoring assumptions. For my analysis, I reduced the monitoring and finance assumptions in USDOE (2017) to be in line with those used in NPC (2019) by adjusting the ratio of monitoring to injection wells from 9:1 to 2:1; reducing the number of 3D seismic studies from 16 to 6; and assuming self-insurance rather than a trust fund for debt financing. I then used the model to calculate the per-ton cost for four different CO_2 injection rates in 13 reservoirs under two sets of monitoring assumptions which I refer to as "base" monitoring assumptions (e.g. NPC (2019) assumptions) and "extra" monitoring assumptions (e.g. USDOE (2017) default assumptions).

I calculated the mean and standard deviation in CO_2 storage costs across the 13 reservoirs in Table 2, weighted by storage capacity, for four CO_2 rates and under both sets of monitoring and finance assumptions. These costs are reported in 2008 dollars in Table 3. The USDOE (2017) model did not solve for two of the smallest and least desirable reservoirs (St. Peter and Paluxy), so these costs were excluded from the mean and standard deviation calculations.

Table 3. U.S. storage cost range (2008$/t$CO_2$) under base monitoring assumptions (Low, Mean, and High columns) and extra monitoring assumptions (Mean with Extra Monitoring column. USDOE (2017) model output reported here.

Rate Mtpa CO_2	Low	Mean	High	Mean with Extra Monitoring
1	$6.81	$11.51	$16.22	$19.67
3.2	$3.67	$5.59	$7.51	$10.59
6	$3.05	$4.70	$6.36	$8.86
15	$2.83	$4.36	$5.90	$8.03

I then used the Producer Price Index to escalate the costs in Tables 3 from 2008 dollars (as reported by USDOE (2017)) to 2019 dollars under both sets of monitoring assumptions to be comparable to the values reported in the NPC (2019) study. These are visible in Table 4. Similar to my CO_2 transport cost range, I applied two standard deviations below and above my mean to calculate the values in the Low and High columns in Tables 3, 4, and 5.

Table 4. U.S. storage cost range (2019\$/tCO_2) under base monitoring assumptions (Low, Mean, and High columns) and extra monitoring assumptions (Mean with Extra Monitoring column). USDOE (2017) model output escalated to 2019 dollars reported here.

Rate Mtpa CO_2	Low	Mean	High	Mean with Extra Monitoring
1	\$7.18	\$12.13	\$17.08	\$20.72
3.2	\$3.87	\$5.89	\$7.91	\$11.15
6	\$3.21	\$4.95	\$6.69	\$9.33
15	\$2.98	\$4.60	\$6.21	\$8.46

After calculating the mean and standard deviation in storage cost for each CO_2 rate in 2019 dollars, I used the NPC (2019) national average cost estimate of \$8/tCO_2 to store 3.2 Mtpa CO_2 to anchor my storage cost range. I did this by calculating a ratio between the NPC (2019) mean cost estimate for storing 3.2 Mtpa CO_2 (aka \$8/tCO_2) and my mean cost estimate for storing the same CO_2 rate under base monitoring assumptions and outlined in Table 4 (\$5.89/tCO_2). This resulted in a ratio of 1.36. I then applied this ratio to my mean storage cost estimates for 1 and 6 Mtpa CO_2 in Table 4 to bring my estimated cost for storing each CO_2 rate under base monitoring assumptions in line with NPC (2019) estimates. As discussed above, I then calculated the costs for 15 Mtpa by extrapolation. These costs are visible in the Mean column in Table 5.

I also examined CO_2 storage costs under extra monitoring assumptions. I applied the ratio of 1.36 directly to the capacity-weighted mean cost I calculated for storing CO_2 under extra monitoring assumptions for 1, 3.2, and 6 Mtpa CO_2 and outlined in Table 4 to adjust them in line with the NPC figures (Table 5). As discussed above, I then calculated the costs for 15 Mtpa by extrapolation. The added cost of extra monitoring alone is broken out in Table 6. As can be seen in Figure 6, CO_2 storage costs decline rapidly with scale and then level off after about 5-6 Mtpa.

Table 5. U.S. storage cost range (2019\$/tCO_2) under base monitoring assumptions (Low, Mean, and High columns) and extra monitoring assumptions (Mean with Extra Monitoring column). USDOE (2017) model output in 2019 dollars adjusted according to ratio with NPC (2019).

Rate Mtpa CO_2	Low	Mean	High	Mean with Extra Monitoring
1	\$9.74	\$16.47	\$23.20	\$28.14
3.2	\$5.25	\$8.00	\$10.75	\$15.14
6	\$4.36	\$6.73	\$9.09	\$12.67
15	\$4.05	\$6.24	\$8.44	\$11.49

Table 6. U.S extra monitoring costs (2019$/$tCO_2$) associated with storing different CO_2 rates.

Rate Mtpa CO_2	Extra Monitoring-Only Costs
1	$11.67
3.2	$7.14
6	$5.95
15	$5.25

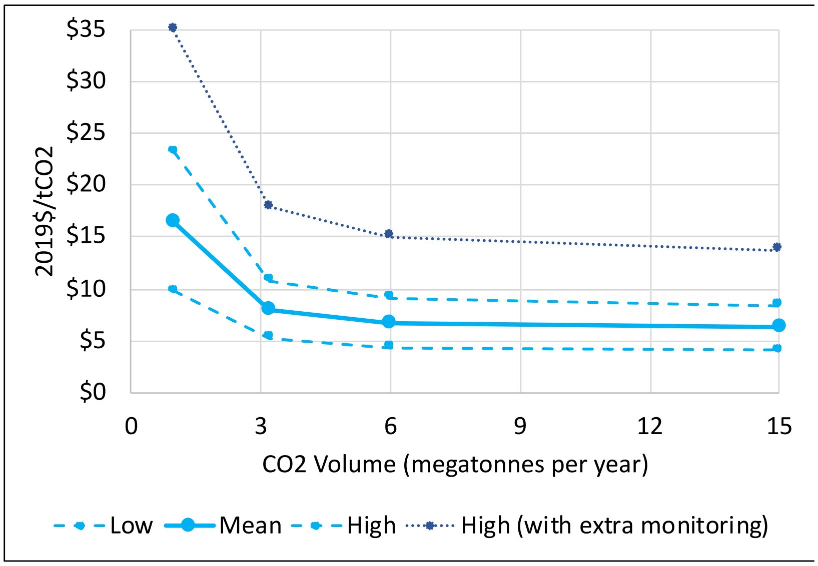

Figure 6. U.S. CO_2 storage cost range in current 2019$/$tCO_2$.

5. Combined CO_2 Transport and Storage Cost Range

5.1. Combined CO_2 Transport and Storage Cost Range

Once I calculated the CO_2 transport and storage cost ranges separately, I compiled them into a combined CO_2 transport and storage cost range. It is important to flag that these costs are reflective of onshore CO_2 pipeline transport and onshore geologic storage (in saline aquifers and depleted oil and gas fields) in the United States. I explore applying these costs to other regions in the next section.

Table 7 shows the combined cost of CO_2 transport and storage for various combinations of scale, transport distance, monitoring requirements, and low and high cost assumptions. For my modelling exercise, I identified three transport distances (0, 100, and 500 miles) reflecting various assumptions about how far CO_2 must be transported from the point of capture to a secure geologic reservoir. The overall CO_2 transport and storage cost ranges from a low of $4/t$CO_2$ to a high of $88.9/t$CO_2$. Note that the $88.9/t$CO_2$ is incurred for transporting a very small amount of CO_2 (1 Mtpa) over a very long distance (500 miles) and assumes extra monitoring requirements for CO_2 storage. Such a project would not likely be developed. A cost of $45/t$CO_2$ is a more reasonable high bound because this reflects transport and storage projects of more realistic scope (1 Mtpa CO_2 over 100 miles, or 3.2 Mtpa CO_2 over 500 miles).

Table 7. Combined CO_2 transport and storage costs in current 2019$/t$CO_2$ for various combinations of scale, transport distance, and monitoring assumptions in the United States.

CO_2 Scale and Distance	Low	Mean	High	High (with extra monitoring)
1 Mtpa, 0 miles	$9.7	$16.5	$23.2	$34.9
1 Mtpa, 100 miles	$12.6	$23.3	$34.0	$45.7
1 Mtpa, 500 miles	$24.1	$50.6	$77.2	$88.9
3.2 Mtpa, 0 miles	$5.3	$8.0	$10.7	$17.9
3.2 Mtpa, 100 miles	$6.5	$11.2	$15.9	$23.1
3.2 Mtpa, 500 miles	$11.6	$24.1	$36.6	$43.8
6 Mtpa, 0 miles	$4.4	$6.7	$9.1	$15.0
6 Mtpa, 100 miles	$5.2	$9.0	$12.7	$18.6
6 Mtpa, 500 miles	$8.7	$17.9	$27.1	$33.0
15 Mtpa, 0 miles	$4.0	$6.2	$8.4	$13.7
15 Mtpa, 100 miles	$4.5	$7.4	$10.4	$15.6
15 Mtpa, 500 miles	$6.3	$12.2	$18.2	$23.4

Figure 7 shows the specific breakdown of transport, storage, and extra monitoring costs for the same combination of scale, transport distance, monitoring assumptions, and low- and high-cost assumptions captured in Table 7. Monitoring costs are identical to those listed in Table 6.

	1 Mtpa								
	0 miles			100 miles			500 miles		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Transport	0.00	0.00	0.00	2.86	6.83	10.80	14.31	34.15	53.99
Storage	9.74	16.47	23.20	9.74	16.47	23.20	9.74	16.47	23.20
Monitoring	0.00	0.00	11.67	0.00	0.00	11.67	0.00	0.00	11.67
TOTAL	9.7	16.5	34.9	12.6	23.3	45.7	24.1	50.6	88.9

	3.2 Mtpa								
	0 miles			100 miles			500 miles		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Transport	0.00	0.00	0.00	1.27	3.22	5.17	6.35	16.11	25.86
Storage	5.25	8.00	10.75	5.25	8.00	10.75	5.25	8.00	10.75
Monitoring	0.00	0.00	7.14	0.00	0.00	7.14	0.00	0.00	7.14
TOTAL	5.3	8.0	17.9	6.5	11.2	23.1	11.6	24.1	43.8

	6 Mtpa								
	0 miles			100 miles			500 miles		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Transport	0.00	0.00	0.00	0.86	2.23	3.60	4.30	11.15	18.00
Storage	4.36	6.73	9.09	4.36	6.73	9.09	4.36	6.73	9.09
Monitoring	0.00	0.00	5.95	0.00	0.00	5.95	0.00	0.00	5.95
TOTAL	4.4	6.7	15.0	5.2	9.0	18.6	8.7	17.9	33.0

	15 Mtpa								
	0 miles			100 miles			500 miles		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Transport	0.00	0.00	0.00	0.44	1.19	1.94	2.22	5.97	9.71
Storage	4.05	6.24	8.44	4.05	6.24	8.44	4.05	6.24	8.44
Monitoring	0.00	0.00	5.25	0.00	0.00	5.25	0.00	0.00	5.25
TOTAL	4.0	6.2	13.7	4.5	7.4	15.6	6.3	12.2	23.4

Figure 7. Breakdown of CO_2 transport and storage costs in current 2019$/t$CO_2$ for various combinations of scale, transport distance, and monitoring assumptions in the United States.

5.2. Key Sources of Variability

My estimates capture five key sources of variability impacting transport and storage costs and listed in order from largest to smallest impact on combined transport and storage costs: 1) transport distance, 2) scale (i.e. quantity of CO_2 transported and stored), 3) extra monitoring assumptions, 4) geologic variability, and 5) transport variability. Transport variability reflects pipeline costs and is driven primarily by pipeline capital costs, as described in section 3.3. Figure 8 shows the sensitivity range of CO_2 transport and storage costs for each of these sources of variability for transporting 3.2 Mtpa CO_2 100 miles onshore via pipeline for permanent geologic storage.

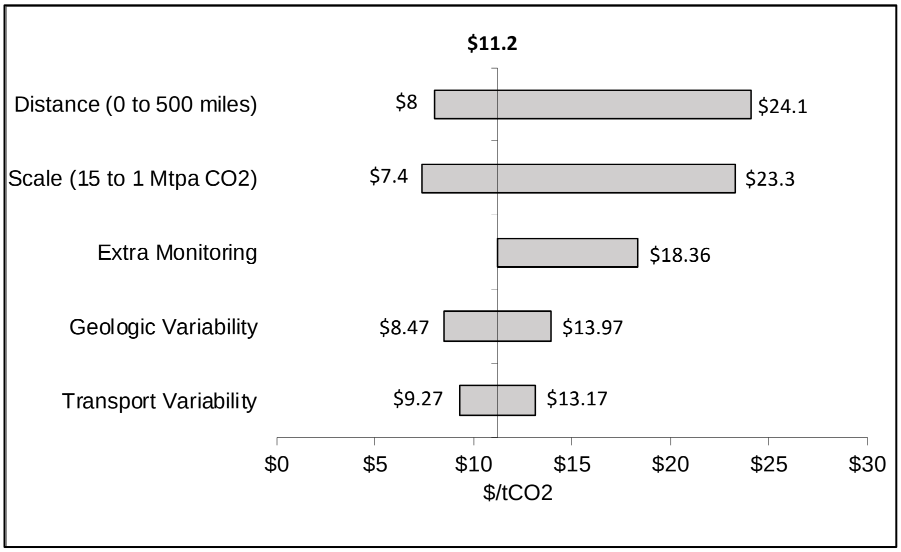

Figure 8. Sensitivity of CO_2 transport, storage and monitoring costs around the base case of 3.2 Mtpa CO_2 being transported 100 miles.

PART II: Modeling Global Climate Pathways with Variable CO_2 Transport and Storage Costs

6. Background on Modeling Approach

6.1. Strengths and Limitations of Integrated Assessment Models

Integrated assessment models (IAMs) are computer models that *integrate* information from human and Earth systems into a single modeling framework and are typically used to *assess* possible outcomes for different policies or decisions. Many analyses of strategies to mitigate climate change over the past 20 years have relied on IAM modeling results, including several Intergovernmental Panel on Climate Change (IPCC) assessment reports. Because IAMs are built to analyze large-scale trends across a variety of economic sectors globally while still capturing regional variation, they are often described as being top-down. By contrast, bottom-up studies for a particular project, region, or type of technology (such as a particular CO_2 transport or storage method) require more detailed and site-specific information because they examine patterns at a much finer geographic or temporal scale. These types of studies contain such detail that incorporating the underlying analytic tools in IAMs would require gathering data that may not be readily available globally, be computationally burdensome, or generate detailed output incompatible with the broad trends IAMs are built to capture. These dynamics reflect the tradeoff in detail vs. scope inherent in many modelling analyses. Since this work is concerned with the role of CCS in future global climate pathways, it focuses on transport and storage cost estimates useful for application to IAMs.

Every analytical tool has strengths and drawbacks, and it is worth reviewing some of those related to IAMs in order to properly interpret and contextualize the results described in subsequent chapters of this thesis. By definition, all models are stylized representations of reality that encompass value-laden input assumptions and a simplification of real-world dynamics. Put more succinctly by statistician George E. P. Box, "all models are wrong, but some are useful" (Box, 1987). It's important to situate IAMs within this framework and communicate to decisionmakers that these models are not crystal balls, but rather one of many tools that can provide insight about key system processes and drivers. IAMs can and should be used in tandem with input from other analytical approaches, scientific experts, and stakeholders and clear documentation of their applications and limitations.

Climate mitigation scenario analysis typically involves setting alternative pathways in which many assumptions are altered in comparison to a business-as-usual pathway. As IAMs in climate analysis became more widespread and sophisticated, alternative pathways came to be defined as a small set of storylines representative of ways the global economy could develop. Many IAMs and pathways are used in mitigation analysis and have been featured in different IPCC reports (IPCC, 2014; Dessens et al., 2016).

For its part in driving the dialogue on climate, the IPCC developed storylines. Initial scenarios were reported in Special Report on Emissions Scenarios (SRES), later products include Representative Concentration Pathways (RCPs) and Shared Socioeconomic Pathways (SSPs). Because of their prevalence in many climate mitigation analyses – including those of influential international governing bodies like the IPCC – IAMs have played a significant role in shaping our understanding of technological solutions and their associated climate outcomes. As such, these models have faced increased scrutiny and targeted criticism in recent years (Rosen, 2015; Rosen & Guenther, 2015; Pindyck, 2013). The chief criticisms tend to focus on i) a lack of transparency in input assumptions and model structure, ii) lack of credibility related to particular input assumptions, iii) over-reliance on particular technologies, and iv) inadequate representation of real-world processes (Gambhir et al., 2019).

IAMs are often criticized for being 'black boxes' because the underlying code and input assumptions are often not publicly available, making it difficult for others to verify and reproduce their results. IAMs for climate mitigation analysis have been criticized for failing to capture realistic patterns related to innovation and behavioral change, as well as for an over-reliance on negative emission technologies like bioenergy with carbon capture and storage (BECCS) to achieve emission targets. These are a sample of the criticisms that have been voiced but it's worth noting that efforts are already underway to address many of the shortcomings. For example, rather than relying on a particular set of predetermined storylines that limit the uncertainty space to be explored and provide no probabilistic interpretation, some IAMs take a probabilistic approach to representing a comprehensive set of both socioeconomic and climate uncertainty (Morris et al., 2021). While imperfect, IAMs remain useful tools for evaluating the potential suite of technologies and policies needed to achieve international climate objectives compared to business as usual.

6.2. Economic Projection and Policy Analysis (EPPA) Model

The Economic Projection and Policy Analysis (EPPA) model is a multi-region, multi-sector model of the world economy. It is part of the IAM, namely the MIT Integrated Global Systems Model (IGSM). The primary goals of the EPPA model is to capture human system dynamics including economic growth, international trade, demographic changes, resource use, anthropogenic greenhouse gas emissions, land use change, and technological advances. It has been used for a wide array of studies, including assessments of the economic implications of developments related to climate and environmental impacts, resource depletion, energy and environmental policies, technology deployment, and future emission pathways. The EPPA model is composed of 18 global regions illustrated in Figure 9. I use EPPA to explore the impact of variations in transport and storage costs on climate pathways that include the CCS option. EPPA is capable of modeling a variety of climate policies and pathways including emission caps and carbon prices as discussed in the next section. With regard to transparency, a public version of EPPA is available online (https://globalchange.mit.edu/research/research-tools/human-system-model/download).

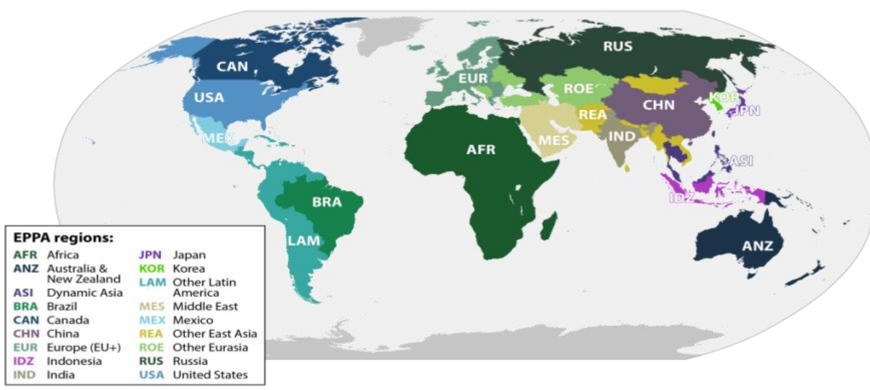

Figure 9. Description of 18 regions represented in MIT's Economic Projection and Policy Analysis (EPPA)

Many well-documented IAM studies combine the cost of CO_2 transport and storage into a single estimate and report costs below \$15/tCO_2 for most CCS deployment scenarios, and some estimates report costs below \$5/tCO_2 (Herzog, 2011; McCoy and Rubin, 2008; Dahowski et al., 2011). After reviewing these and other studies, the IPCC Fifth Assessment Report (IPCC, 2014) reported that a common assumption for the cost of transport and storage of CO_2 is \$10/tCO_2. Until now, many of the IAMs underlying climate mitigation analyses – including EPPA - have treated CO_2 transport and storage costs as uniform in all regions without accounting for variability across geographic, geologic, and institutional settings. The results in the subsequent chapters explore how accounting for this variation has impacted model outcomes in EPPA.

7. Uniform CO_2 Transport and Storage Costs in All Regions

To explore the impact of transport and storage costs on climate outcomes, I modeled a scenario in EPPA that applies a greenhouse gas (GHG) emissions profile consistent with a 66% probability of limiting global temperature rise to 2°C above preindustrial levels. This scenario applies an escalating, globally uniform, price of carbon emissions as did Morris et al. (2020). I first ran a series of "uniform cost" cases where transport and storage costs were fixed in all regions at a particular value, ranging in different cases from \$0 to \$90/tCO_2, including the previous "reference case" assumption of \$10/tCO_2. These results are shown in Figure 10, with the *Reference Case* indicated by a black square and the values corresponding to the endpoints of my cost range of \$4 to \$45/tCO_2 from Chapter 5 indicated by x's. The *Reference Case* results in 425 Gt CO_2 captured and stored cumulatively by 2100 – identical to the level found in Morris et al. (2020). By contrast, the low and high range of my transport and storage cost range correspond to cumulative CO_2 captured and stored of 513 to 65 Gt, respectively. At a global level, different assumptions about transport and storage costs impact the overall level of CCS deployment and by extension the cumulative CO_2 captured and stored by the end of the century. When uniform transport and storage costs are assumed, the model estimated cumulative CO_2 transported and stored decreases with increasing assumed cost as is visible in Figure 10.

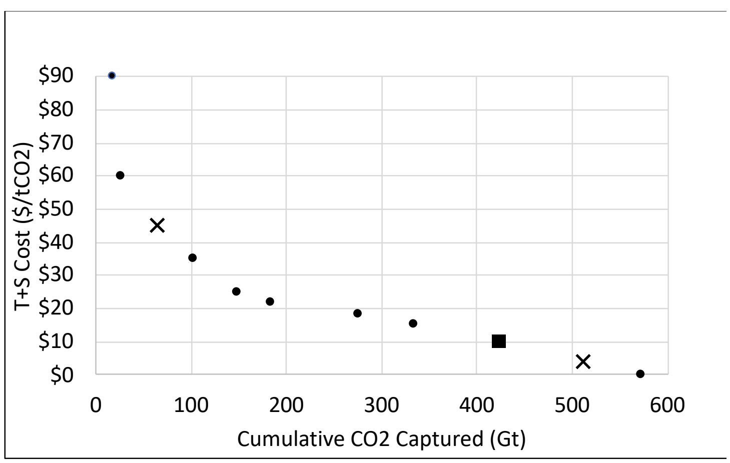

Figure 10. Cumulative Global CO_2 captured and stored (2020-2100) under a scenario that limits global warming to 2°C and with uniform transport and storage costs in all regions. Reference Case is reflected by the square; endpoints of my cost range of \$4 to \$45/tCO_2 is reflected by x's.

Table 8. Cumulative Gt CO_2 captured and stored (2020-2100) by selected EPPA regions for different transport and storage cost assumptions when warming is limited to 2°C.

Modeling Case		USA	China	India	EU	Other Regions	Total
Reference	$10/t CO_2	29	174	72	16	134	425
Uniform	$4/t CO_2	38	213	75	21	166	513
T+S	$45/t CO_2	12	1	31	6	16	65
Costs	$90/t CO_2	6	0	1	6	5	18

Table 8 details the results for four representative EPPA regions that reflect different geographic, geologic, and institutional settings of interest. CCS deployment in China in especially sensitive to small changes in transport and storage costs, as indicated by its relatively flat curve compared to other regions in Figure 11. In many ways, this sensitivity is a byproduct of the EPPA model architecture, which assumes that other power generation options such as nuclear have lower or similar capital costs as coal with CCS in China. As a result, EPPA predicts that moderate increases in transport and storage cost make CCS uncompetitive in China. Depending on the capital cost assumptions for different power generation technologies, this finding may differ in other models.

China captures and stores almost no CO_2 at a transport and storage cost of $35/t CO_2 or higher. This is a sharp drop from 174 Gt CO_2 captured and stored in China under the *Reference Case* assumption of $10/t CO_2 and is a pattern that differs markedly from the other regions. The other regions in Table 8, by contrast, still deploy small amounts of CCS at transport and storage cost as high as $45/t CO_2. India is the only other region listed here to nearly eliminate CCS, but it does so at markedly higher transport and storage costs than China, zeroing out closer to $60/t CO_2. By contrast, CCS continues to play a role in Europe and the United States even at the highest possible transport and storage costs. The amount of cumulative CO_2 captured and stored bottoms out at around 6 Gt CO_2 in both regions after transport and storage costs increase above a particular threshold. In Europe, this threshold is apprxoimately $35/t CO_2 while in the United States it's closer to $60/t CO_2.

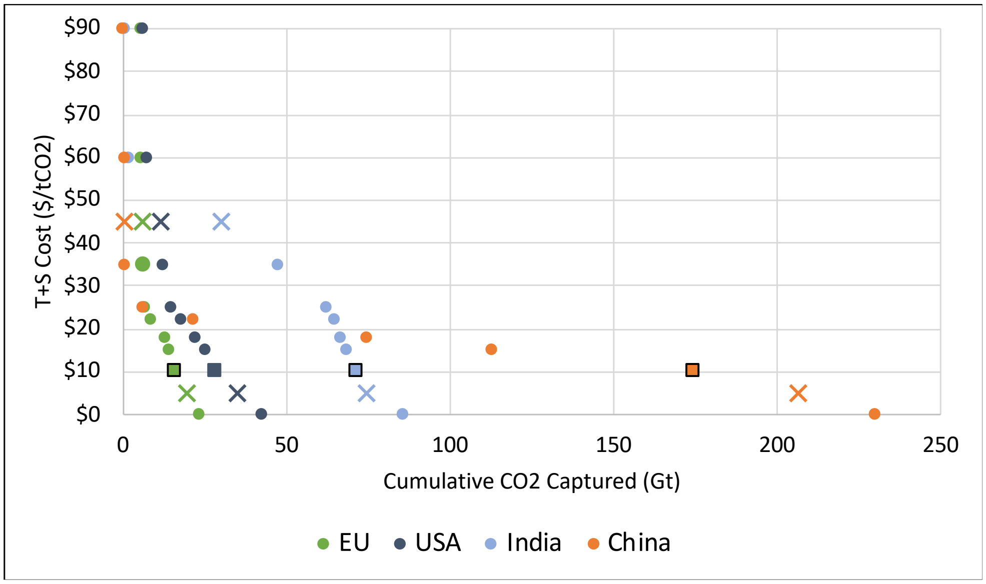

Figure 11. Cumulative Regional CO_2 captured and stored (2020-2100) under a scenario that limits global warming to 2°C and with uniform transport and storage costs in all regions. Reference Case is reflected by the squares; my cost range of $4 to $45/t$CO_2$ is reflected by x's.

8. Varying CO_2 Transport and Storage Costs

8.1. Modeling Cases

In this chapter, I explore several modeling cases with differing CO_2 transport and storage costs assigned to each geographic region in the EPPA model. I describe how I built the *Base Case* and two other illustrative transport and storage cost cases along with a discussion of the subsequent modeling results. Chapter 9 outlines a series of additional sensitivities I performed for a few select regions and their accompanying results. While I use EPPA to model the impact of my transport and storage cost assumptions, these cases could be also applied to other integrated assessment models.

- *Reference Case*: assumes a uniform transport and storage cost of \$10/tCO_2 in all EPPA regions and does not specify the scale of CO_2 or distance transported.
- *Base Case*: assumes variable transport and storage costs in different regions as laid out in Table 9. In this case, it is assumed 3.2 Mtpa CO_2 is transported 100 miles.
- *CCS Networks and Clusters Case*: assumes variable transport and storage costs in different regions as laid out in Table 11. In this case, it is assumed 15 Mtpa CO_2 is transported 100 miles.
- *Low-Cost EU Case*: identical to the *Base Case* assumptions, except Europe is assumed to embrace onshore transport and storage instead of ship transport for offshore storage. As a result, Europe is assigned to the medium-cost tier (Tier 2) in Table 9 instead of the shipping cost tier (Tier 4).

Many IAMs like EPPA assume a uniform CO_2 transport and storage cost of \$10/tCO_2 for all regions regardless of the quantity of CO_2 being transported and stored and other underlying assumptions - I refer to this as the *Reference Case*. As discussed in Chapter 5, my *Base Case* assumes 3.2 Mt of CO_2 is transported 100 miles via pipeline each year for onshore storage in the United States. I calculated the combined cost to transport and store CO_2 under these conditions to be \$11.2/tCO_2. To estimate variation in CO_2 transport and storage costs in other regions in the *Base Case*, I developed four cost tiers: low-, medium-, and high-cost assumptions for onshore CO_2 pipeline transport and storage, and one tier assuming shipping and offshore storage (Table 9).

I assume my *Base Case* transport and storage cost of \$11.2/tCO_2 calculated for the United States defines the lowest cost tier in Table 9 (tier 1) because the United States is the global leader in CCS deployment and has robust oil and gas infrastructure and production capacity. As such, I don't expect other regions to exhibit transport and storage costs lower than this, all else equal. I built the highest cost tier (tier 4) to reflect the cost to transport CO_2 via ship for offshore storage based on recent estimates from the Northern Lights Project. The medium-cost tier (tier 2) uses the high-cost assumptions for transporting 3.2 Mtpa CO_2 over 100 miles for storage without extra monitoring (see Table 7 in Chapter 5). The high-cost tier (tier 3) is the midpoint between the medium-cost and shipping tiers.

Table 9. Regional inputs for CO_2 transport and storage costs for the Base Case. Costs are in current 2019\$/tCO_2.

	Tier 1 - Low Cost	Tier 2 - Medium Cost	Tier 3 - High Cost	Tier 4 - Shipping Cost
Transport Cost (\$/tCO_2)	\$3.22	\$5.17	N/A	N/A
Storage Cost (\$/tCO_2)	\$8.00	\$10.75	N/A	N/A
Total Cost (\$/tCO_2)	**\$11.22**	**\$15.92**	**\$25.86**	**\$35.8**
Assumptions	Mean value for 3.2 Mtpa CO_2, 100 miles from Table 7	High value for 3.2 Mtpa CO_2, 100 miles from Table 7	Midpoint between Medium Cost and Shipping tiers	Northern Lights Project, Low Range
EPPA Regions	USA; Middle East; Russia; Canada; Mexico	China; Australia; Brazil; Indonesia; Other Latin America; Other Eurasia; Dynamic Asia; Other East Asia	Africa; India	Europe; Japan; Korea

As can be seen in Table 9, I assigned each EPPA region into one of the four cost tiers. To do so, I considered key factors I identified as proxies for the cost of transporting and storing CO_2: 2015 oil and gas production and available years of CO_2 storage. These variables are visible in Table 10. I calculated years of available CO_2 storage in each region by dividing the lower estimate of total CO_2 storage capacity estimated by Kearns et al. (2017) by 2015 CO_2 emissions in each region. As previously stated, I assigned the United States to tier 1 because I assume it reflects the lower threshold of transport and storage costs globally.

I assigned Europe, Korea, and Japan into tier 4 because I assume these regions will pursue offshore CO_2 storage. Europe is actively injecting CO_2 into offshore reservoirs in the North Sea as part of the Northern Lights Project, which involves a combination of ship and offshore pipeline transport. Moreover, until recently Europe had banned the cross-border transport of CO_2 as part of the London Protocol, which made onshore CO_2 transport and storage difficult if not nearly impossible. Meanwhile Japan and Korea produce no oil and gas and have few years of CO_2 storage available (see Table 10). Recent announcements from the JGC Corporation also suggest Japan is seriously considering CO_2 ship transport and offshore storage.

Table 10. EPPA Region Characteristics.2015 CO_2 emissions are drawn from BP (2019) Statistical Review of Global Energy.

CO_2 storage capacity figures taken from Kearns et al. (2017). 2015 CO_2 emissions include fossil and industrial emissions.

EPPA Region	2015 Oil & Gas Production (Mtoe)	2015 CO_2 emissions (Gt)	CO_2 Storage Capacity (Gt)	Years of CO_2 Storage
Middle East	1,930	1.65	492	298
USA	1,207	5.06	812	160
Russia	1,047	1.53	1234	808
Africa	563	1.30	1563	1,207
Other Latin America	399	0.92	606	662
Canada	363	0.69	318	462
China	332	11.69	403	34
Other Eurasia	279	1.40	485	345
Dynamic Asia	175	1.21	119	98
Mexico	169	0.55	138	251
Brazil	153	0.51	297	584
Other East Asia	126	0.56	272	485
Indonesia	106	0.54	163	302
Australia	83	0.49	595	1,210
India	65	2.22	99	45
Europe	392	3.67	302	82
Japan	0	1.31	8	6
Korea	0	0.82	3	4

To assign the remaining 14 EPPA regions into cost tiers, I considered the variables listed in Table 10 as guidance and in consultation with geologists and other experts. The Middle East, Russia, and the United States produce a lot of oil and gas – factors that indicate mature oil and gas infrastructure and by extension cost-effectiveness CO_2 pipeline transport and storage. As such, I assigned Russia and the Middle East to Tier 1. North America overall has a relatively interconnected and mature oil and gas infrastructure as well as good CO_2 storage potential, so I assigned Canada and Mexico to Tier 1 alongside the United States. I assigned all other EPPA regions into the medium cost tier (Tier 2) except for India and Africa.

I assigned India to the high cost tier (Tier 3) because it produces little oil and gas and has limited CO_2 storage potential compared to the other EPPA regions. What's more, India has not expressed serious proposals for offshore CO_2 storage like Europe, Japan, and Korea. Africa, by contrast, appears relatively favorable based on oil and gas production and years of CO_2 storage. However, this is a special case because oil and gas production is dominated by a small handful of countries rather than representative of the continent as a whole. Moreover, the World Bank development indicators suggest that it is relatively difficult and costly to do business across most of the continent (World Bank, 2019). As such, I assigned Africa to Tier 3 alongside India. It is worth stressing that the factors I considered in consultation with experts in sorting the EPPA regions into cost tiers are guidance only and due in part to a lack of sufficient data as proxies for the cost of transport and storage across the globe.

I examined two additional modeling cases beyond the *Base Case*. One assumes lower transport and storage costs from economies of scale associated with the development of CCS networks and clusters discussed in Chapter 3 (see Table 11). For this case, I sorted the 18 EPPA regions into the same cost tiers as in the *Base Case*, though the overall transport and storage costs are lower. The other case assumes Europe has lower transport and storage costs. The transport and storage costs in this case are identical to the *Base Case*, except Europe is assigned to Tier 2 instead of Tier 4. This case reflects a scenario where Europe stores CO_2 onshore, which it has not seriously considered until recently because of legal barriers to the onshore cross-border transport of CO_2.

Table 11. Regional inputs for CO_2 transport and storage costs for the CCS Networks and Clusters Case. Costs are in current 2019$/$tCO_2$.

	Tier 1 - Low Cost	Tier 2 - Medium Cost	Tier 3 - High Cost	Tier 4 - Shipping Cost
Transport Cost ($/$tCO_2$)	$1.19	$1.94	N/A	N/A
Storage Cost ($/$tCO_2$)	$6.24	$8.44	N/A	N/A
Total Cost ($/$tCO_2$)	**$7.44**	**$10.38**	**$23.09**	**$35.8**
Assumptions	Mean value for 15 Mtpa CO_2, 100 miles from Table 7	High value for 15 Mtpa CO_2, 100 miles from Table 7	Midpoint between Medium Cost and Shipping tiers	Northern Lights Project, Low Range
EPPA Regions	USA; Middle East; Russia; Canada; Mexico	China; Australia; Brazil; Indonesia; Other Latin America; Other Eurasia; Dynamic Asia; Other East Asia	Africa; India	Europe; Japan; Korea

8.2. Results and Discussion

Just like the uniform cost cases described in Chapter 7, I used EPPA to examine the impact of regional transport and storage cost variability under a carbon constrained future when global temperature rise is limited to 2°C by applying an escalating, globally uniform, price of carbon emissions. Results are shown in Figure 12, which modifies Figure 10 from Chapter 7 by adding the results from the three modeling cases described above. The same is true of Table 12 below, which modifies Table 8 from Chapter 7 to include the three modeling cases.

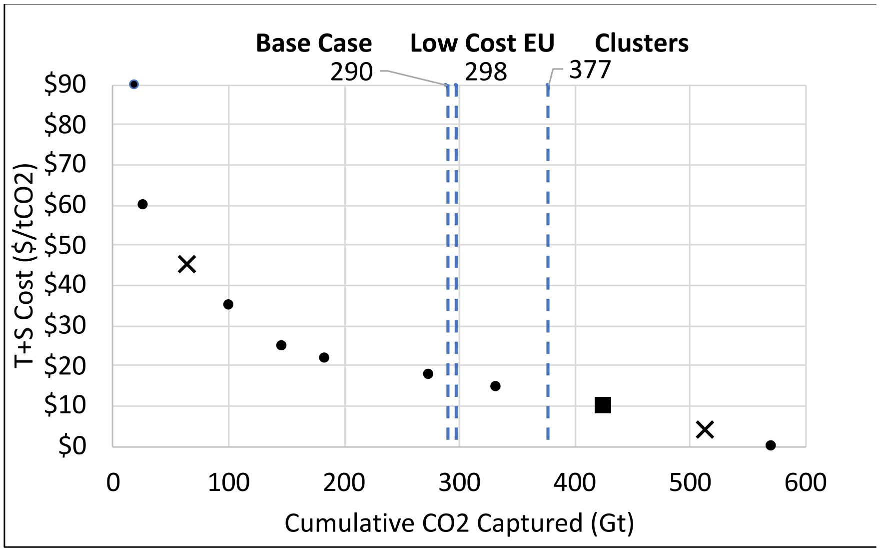

Figure 12. Cumulative global CO_2 captured and stored (2020-2100) under a scenario that limits warming to 2°C. Points reflect cases where transport and storage costs are uniform in all regions (*Reference Case* is reflected by the square; our cost range of $4 to $45/t$CO_2$ is reflected by x's). Vertical lines reflect cases where transport and storage costs vary by EPPA region.

Table 12. Cumulative Gt CO_2 captured and stored (2020-2100) by EPPA region for different transport and storage costs assumptions when warming is limited to 2C.

Modeling Case		USA, Tier 1	China, Tier 2	India, Tier 3	EU, Tier 4	Other Regions	Total
Reference	$10/t$CO_2$	29	174	72	16	134	425
Uniform T+S Costs	$4/t$CO_2$	38	213	75	21	166	513
	$45/t$CO_2$	12	1	31	6	16	65
	$90/t$CO_2$	6	0	1	6	5	18
Regional Cases	Base Case	28	103	61	6	92	290
	CCS Networks & Clusters	30	173	62	6	106	377
	Low Cost EU	28	103	61	14	92	298

Under my *Base Case* transport and storage cost assumptions outlined in Table 7, 290 Gt CO_2 is captured and stored cumulatively by 2100 - a reduction of 32% from the *Reference Case* (see Figure 4 and Table 12). In other words, less CO_2 is cumulatively captured and stored globally by 2100 when transport and storage costs vary regionally compared to the *Reference Case* assumption of a uniform transport and storage cost of $10/t$CO_2$. Incorporating regional variation in CO_2 transport and storage cost input assumptions is an important driver of global and regional model results. In most regions, incorporating realistic variation in transport and storage costs as outlined in the *Base Case* reduces and delays large-scale CCS deployment (see Figure 13) compared to the *Reference Case*.

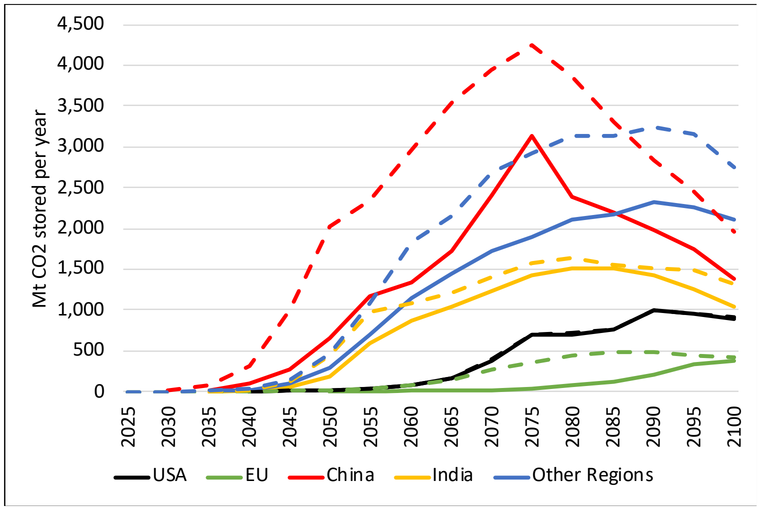

Figure 13. Annual CO_2 captured and stored in the *Reference Case* (dashed lines) and *Base Case* (solid lines) under a scenario that limits warming to 2°C, by EPPA region.

Now I'm going to focus on regional results. Europe faces high transport and storage costs in the *Base Case* of ~\$35/tCO_2 because it is assumed to employ shipping and offshore storage. This is much higher than \$10/tCO_2 assumed in the *Reference Case* and reduces cumulative CO_2 captured and stored in Europe from 16 to 6 Gt CO_2 by 2100 (a reduction of over 60%). It is worth flagging that in the uniform cost cases, cumulative CO_2 captured and stored in Europe also bottomed out at 6 Gt CO_2 when transport and storage exceeded \$35/tCO_2. In the *Base Case*, large-scale ramp-up of natural gas plants equipped with CCS is delayed in Europe until 2070 (Figure 14), reducing cumulative electricity generated from these sources by over 50% compared to the reference case. Meanwhile, electricity generation from wind and solar energy increases by roughly 13%.

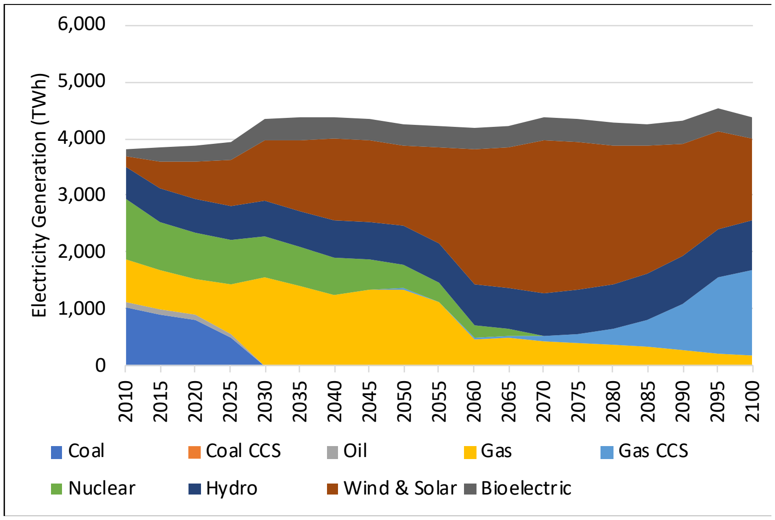

Figure 14. Annual electricity generation in Europe in the Base Case under a scenario that limits warming to 2°C.

India is in the next highest cost tier (tier 3) with transport and storage costs of ~\$25.86/tCO_2. Under a 2°C scenario, India witnesses a 27% increase in nuclear power generation and a 16% reduction in power generation from coal with CCS due to higher transport and storage costs than in the *Reference Case* (Figure 14). This is accompanied by a reduction of 10 Gt in cumulative CO_2 stored and captured by 2100. The significantly higher transport and storage costs in these regions in the *Base Case* reduces CCS deployment in the power sector.

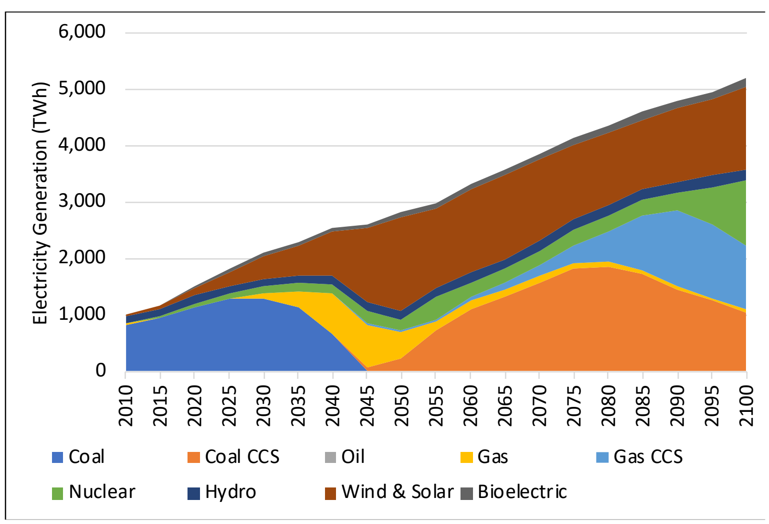

Figure 15. Annual electricity generation in India in the Base Case under a scenario that limits warming to 2°C.

China is in the medium transport and storage cost tier (tier 2) with transport and storage costs of ~\$15.92/tCO_2 in the *Base Case* – only moderately higher than the *Reference Case* cost of \$10/tCO_2. Electricity generation from coal with CCS is cut by 40% in China compared to the *Reference Case*, much of which is replaced by nuclear power (Figure 15). This results in roughly 70 fewer Gt CO_2 cumulatively stored between 2020 and 2100, with a peak in 2075 in annual CO_2 captured (see Figure 13). This is noteworthy given the transport and storage costs increased only moderately compared to the *Reference Case* and suggests CCS deployment in China may be more sensitive to CCS costs than was previously understood. In China, other power generation options such as nuclear have lower or similar capital costs to coal with CCS such that moderate increases in transport and storage cost make CCS uncompetitive. Similar patterns were evident in China in Chapter 7 under uniform transport and storage costs.

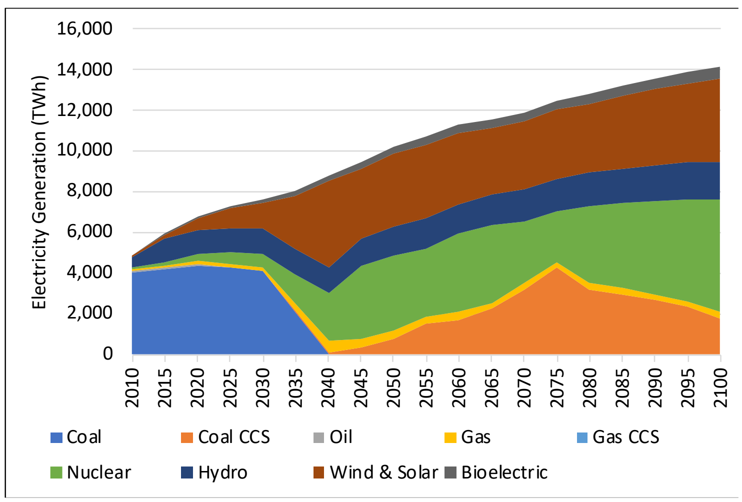

Figure 16. Annual electricity generation in China in the Base Case under a scenario that limits warming to 2°C.

The United States is in the low-cost tier of \$11.2/tCO_2. Because U.S. transport and storage costs are only slightly higher than in the *Reference Case*, the *Base Case* results do not differ much. This is evident in Table 12. I included a depiction of the electricity generation profile of the United States in the *Base Case* for reference (Figure 17).

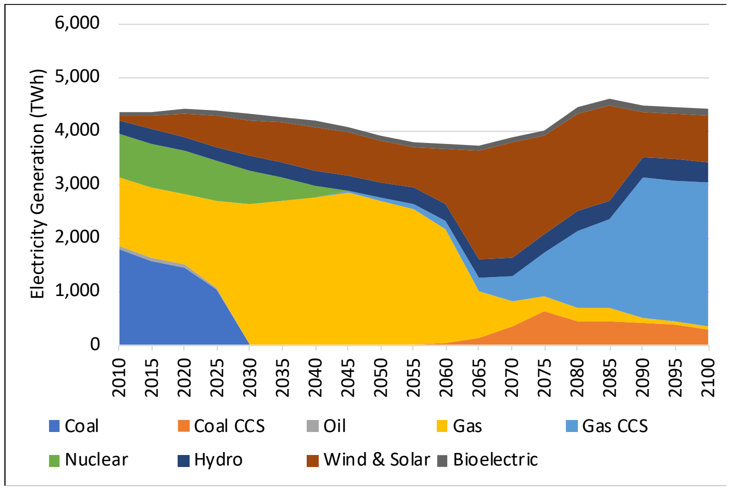

Figure 17. Annual electricity generation in the United States in the Base Case under a scenario that limits warming to 2°C.

I also examined a case where I assume low transport and storage costs due to the economies of scale achieved by rollout of shared CO_2 transport networks and CCS clusters (Table 11). CCS transport networks and storage clusters increase global capacity to capture and store CO_2. In this *Clusters Case*, 377 Gt CO_2 are captured and stored cumulatively by the end of the century – a 30% increase from the *Base Case*. In the *Clusters Case,* I assume identical (in the case of Europe) or very similar (in the case of India and China) transport and storage costs as the *Base Case*, so the results are very similar to the *Base Case* in these regions (see Figures 13 and 18). The United States sees approximately a 25% reduction in transport and storage costs of compared to the *Reference Case* (~\$7.4/tCO_2), but this does not produce noticeable changes in the U.S. electricity profile other than a slight increase (14%) in electricity generation from coal plants with CCS.

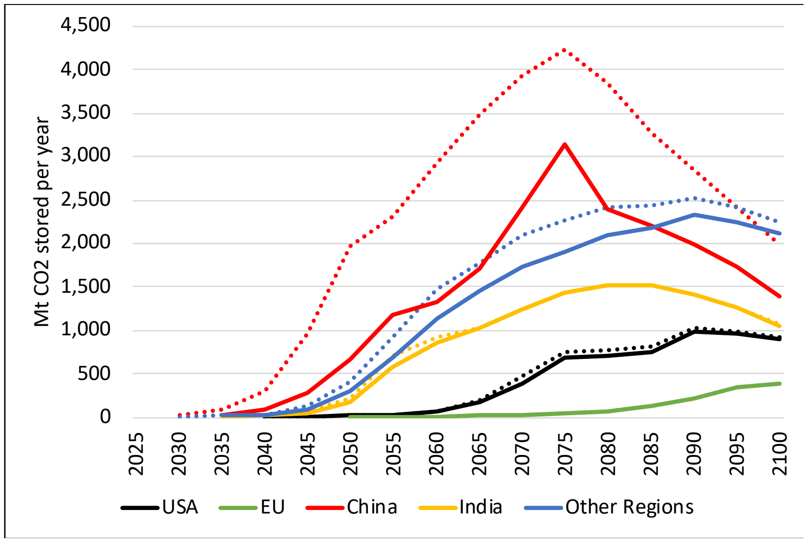

Figure 18. Annual CO_2 captured and stored in the CCS Networks and Clusters Case (dotted lines) and Base Case (solid lines) under a scenario that limits warming to 2°C, by EPPA region.

I also examined a case where Europe experiences low transport and storage costs – either because it employs offshore pipelines instead of ships, starts storing CO_2 onshore, or the Northern Lights Project sees rapid cost declines. Under such *Low Cost EU* assumptions, Europe is assigned to the medium cost tier of ~$15.92/t$CO_2$ – moderately higher than the *Reference Case* transport and storage costs but below *Base Case* assumption of ~$35/t$CO_2$. When I assume Europe has low transport and storage costs, an additional 8 Gt CO_2 is cumulatively captured and stored globally compared to the *Base Case*, driven by a doubling in the amount of electricity generated from natural gas plants with CCS in Europe. Under these assumptions, slightly less (2 Gt) CO_2 is stored cumulatively by 2100 in Europe compared to the *Reference Case*. See Figure 19 for a comparison of annual CO_2 captured and stored in Europe across the cases, and Tables 13 and 14 for snapshots of annual CO_2 captured and stored in 2050 and 2075 in four key regions across the cases.

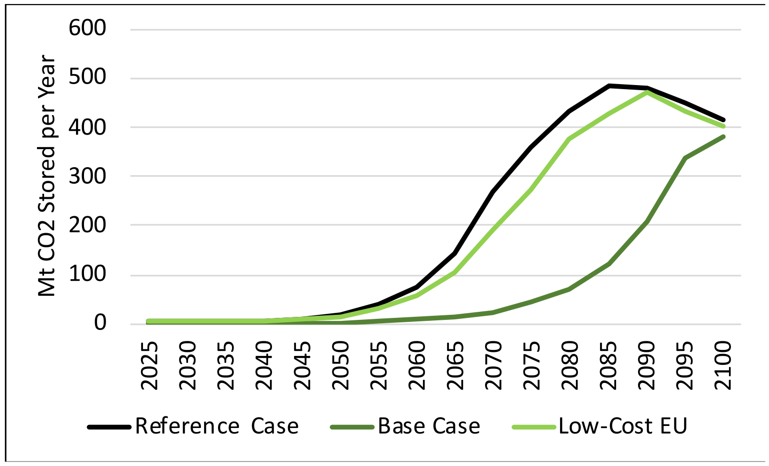

Figure 19. Annual CO_2 captured and stored in Europe under a scenario that limits warming to 2°C, by modeling case.

Table 13. Snapshot of Mt CO_2/year captured and stored in 2050 by EPPA region for different transport and storage costs assumptions when warming is limited to 2C.

Modeling Case		USA	EU	China	India	Other Regions	Total
Reference	\$10/tCO_2	14	19	2,017	443	466	2,959
Uniform T+S Costs	\$4/tCO_2	18	24	2,636	554	1,133	4,365
	\$45/tCO_2	6	2	0.5	27	15	50
	\$90/tCO_2	2	2	0	1	3	8
Regional Cases	Base Case	14	2	654	181	302	1,152
	CCS Networks & Clusters	14	2	1,972	224	417	2,629
	Low Cost EU	14	16	655	181	301	1,166

Table 14. Snapshot of Mt CO_2/year captured and stored in 2075 by EPPA region for different transport and storage costs assumptions when warming is limited to 2C.

Modeling Case		USA	EU	China	India	Other Regions	Total
Reference	\$10/tCO_2	693	358	4,242	1,584	2,912	9,789
Uniform T+S Costs	\$4/tCO_2	945	504	4,377	1,638	3,590	11,053
	\$45/tCO_2	100	42	7	904	231	1,284
	\$90/tCO_2	44	42	3	17	47	154
Regional Cases	Base Case	691	42	3,143	1,437	1,905	7,218
	CCS Networks & Clusters	751	42	4,230	1,440	2,267	8,731
	Low Cost EU	691	274	3,149	1,439	1,905	7,458

9. Regional Sensitivities

In addition to the modeling cases in Chapter 8, I identified two regions of interest in which to explore sensitivities in transport and storage costs. I developed sensitivities that would either represent more realistic policy developments in each region or that would offer valuable insight about the impact of infrastructure costs on CCS deployment and climate outcomes. I performed two sensitivities each on the *Base Case* and *CCS Clusters Case* in the United States, for a total of four U.S. sensitivities. I selected the United States as a region of interest because I based my transport and storage cost estimates for the U.S. context. The United States likely reflects the low end of the transport and storage cost range and has an active and favorable policy environment for CCS. The U.S. has also embraced ambitious CO_2 emission targets and, as such, I wanted to deepen my understanding of how different transport and storage cost assumptions impact the role of CCS in the U.S. climate mitigation portfolio. I also performed one sensitivity each on the *Base Case* and *CCS Clusters Case* in China, for a total of two China sensitivities. I selected China because my results from Chapters 7 and 8 indicate CCS deployment in this region is sensitive to small changes in transport and storage costs.

9.1. United States

I consider two *Extra Monitoring* sensitivities in the United States – one for the *Base Case*, and one for the *CCS Clusters Case*. For the former, I assume *Base Case* transport and storage costs in all EPPA regions except the United States, for which I add \$7.14/tCO_2 to account for the cost to drill extra wells to monitor CO_2 injected in onshore geologic reservoirs. These costs are based on my estimate from Chapter 5 for a CO_2 flow rate of 3.2 Mtpa transported over 100 miles (see Figure 7) and result in a U.S. transport and storage cost of \$18.36/tCO_2 for this sensitivity. For the latter, I assume *CCS Clusters* transport and storage costs in all EPPA regions except the United States, for which I add \$5.25/tCO_2 to account for extra monitoring costs. These costs are based on my estimate from Chapter 5 for a CO_2 flow rate of 15 Mtpa transported over 100 miles (see Figure 7) and result in a U.S transport and storage cost of \$13.17/tCO_2 for this sensitivity.

I consider *Extra Monitoring* sensitivities in the United States because it has embraced a number of policies with prescriptive conditions under which onshore transport and storage of CO_2 is allowed and incentivized. Post-injection site care is required for anywhere from 50 to 100 years in the United States depending on the state, each of which has varying levels of stringency related to the financial burden and exposure to legal liability for onshore CO_2 storage projects. Given this policy environment, I felt it would be informative to model a sensitivity that assumes the United States embraces even more ambitious safeguards to ensure the long-term disposal of CO_2. I wanted to understand, in particular, how results vary depending on different levels of CCS deployment, which is why I performed sensitivities on both the *Base Case* and *CCS Clusters Case*. I do not model this sensitivity in China because I assume the regulatory regime there is unlikely to embrace a rigorous monitoring requirement for onshore CO_2 storage.

Under a sensitivity with rigorous monitoring requirements in the United States, CCS deployment on coal and gas plants is reduced. Compared to the *Base Case*, cumulative energy generation from each of these resources falls in the U.S. by 20% and 24% respectively by 2100. This results in 6.5 fewer Gt CO_2 captured and stored cumulatively in the U.S. by 2100, a drop of 24% from the *Base Case* level of 28.5 Gt CO_2. This is not unsurprising given that U.S. transport and storage costs increased to \$18.36/tCO_2 - an increase of nearly 2/3 from the *Base Case* U.S. level of \$11.22/tCO_2. See Table 15 for a breakdown of the U.S. transport and storage cost input assumption and select results for each of the modeling cases and U.S. sensitivities.

Table 15. Breakdown of U.S. transport and storage cost inputs and cumulative CO_2 captured and stored (2020-2100) for key modelling cases and sensitivities.

	Transport and Storage Cost Case	U.S. transport and storage cost (\$/tCO_2)	U.S. Cumulative Gt CO_2 captured and stored (2020-2100)
Uniform Cases	\$4/tCO_2	\$4	38
	Reference Case	\$10	29
	\$45/tCO_2	\$45	12
	\$90/tCO_2	\$90	6
Regional Modeling Cases	*Base Case*	\$11.2	28
	Clustering	\$7.4	30
Base Case Sensitivities with Variable U.S. costs	Extra Monitoring	\$18.4	22
	45Q	\$50/tCO_2 credit on *Base Case* costs	85
CCS Clusters Case Sensitivities with Variable U.S. costs	Extra Monitoring	\$13.2	27
	45Q	\$50/tCO_2 credit on *CCS Clusters* costs	88

Under a sensitivity when CCS clusters and hubs emerge in the United States, extra monitoring requirements have significantly less of a dampening effect on CCS deployment on natural gas plants. In this sensitivity, transport and storage costs increase over 75% from the *CCS Clusters Case* level of

\$7.44/tCO_2 to \$13.17/tCO_2. This reduces CCS deployment on coal plants but does not significantly reduce CCS deployment on natural gas plants, and results in only 3 fewer Gt CO_2 cumulatively captured and stored in the U.S. by 2100 than the *CCS Clusters Case* level of 30 Gt CO_2. In both the *Base Case* and *CCS Clusters Case*, gas plants equipped with CCS generate roughly four times as much energy cumulatively by 2100 as coal plants with CCS in the United States, even when rigorous monitoring requirements are assumed. This is indicative of the competitive role that natural gas power plants with CCS can play in the U.S. decarbonization portfolio, particularly if stringent monitoring requirements for onshore CO_2 storage raise transport and storage costs.

I also consider two *45Q* sensitivities in the United States – one for the *Base Case*, and one for the *CCS Clusters Case*. For the former, I assume *Base Case* transport and storage costs in all EPPA regions except the United States, for which I subtract \$50/tCO_2 from the *Base Case* U.S. cost assumption. This results in a net credit of \$38.78/tCO_2 for the overall CCS cost in the United States. For the latter, I assume *CCS Clusters Case* transport and storage costs in all EPPA regions except the United States, for which I subtract \$50/tCO_2 from the U.S. *CCS Clusters Case* cost assumptions. This results in a net credit of \$42.56/tCO_2. These sensitivities illustrate the sensitivity of different U.S. mitigation options to low CO_2 transport and storage costs.

I developed this sensitivity to explore the generous incentives for CCS currently in place or that are being considered in the United States. In 2018, the United States increased the value of the 45Q tax credit to store CO_2 permanently underground to \$50/tCO_2 and in 2020 extended the timeframe for projects to commence construction (and thus qualify for the tax credit) by two years. Since 2018, U.S. lawmakers have also backed bills that would support the buildout of CCS infrastructure, including passage of the USE-IT Act in 2020 and introduction of the SCALE Act in 2021. These bills could hasten the establishment of CCS clusters, pipeline networks, and storage hubs needed to facilitate large-scale rollout of CCS and the economies of scale associated with it. I felt it would be informative to explore a sensitivity that reduces the overall cost of the CCS value chain by lowering the cost CO_2 transport and storage infrastructure at different levels of CCS deployment.

A \$50/tCO_2 tax credit in the United States significantly increases and hastens deployment of CCS compared to the *Base Case*, particularly on coal plants. In this sensitivity, the tax credit effectively eliminates transport and storage costs in the U.S. and reduces the overall CCS cost by 31% for coal plants and 15% for natural gas plants. As a result, the amount of CO_2 cumulatively captured and stored by 2100 in the U.S. nearly triples compared to the *Base Case* level of 28.5 Gt CO_2. Cumulatively, U.S. energy generation from coal with CCS increases by a factor of 5 while that from natural gas with CCS increases by 8% by 2100 compared to the *Base Case*. As a result, coal with CCS supplies a greater share of cumulative energy generation in the U.S. by the end of the century than gas with CCS – a departure from trends in the *Base Case* in which natural gas plants with CCS supply roughly 3 times more cumulative energy generation than coal with CCS.

When CCS clusters and transport networks are assumed, a \$50/tCO_2 tax credit hastens the deployment of CCS by roughly 5 years compared to the 45Q sensitivity without CCS clusters. The sensitivity also results in 3.5 times more cumulative energy generation from coal with CCS in the U.S. by 2100 than the *CCS Clusters Case*, while energy generation from natural gas plants with CCS increases 43%. The result is 88 Gt CO_2 cumulatively captured and stored in the United States by 2100 compared to 30 Gt CO_2 in the *CCS Clusters Case* – nearly a 3-fold increase. Figure 20 displays the cumulative and annual CO_2 captured and stored in the United States through 2100 respectively across all four sensitivities as well as in the *Base Case* and *CCS Clusters Case*.

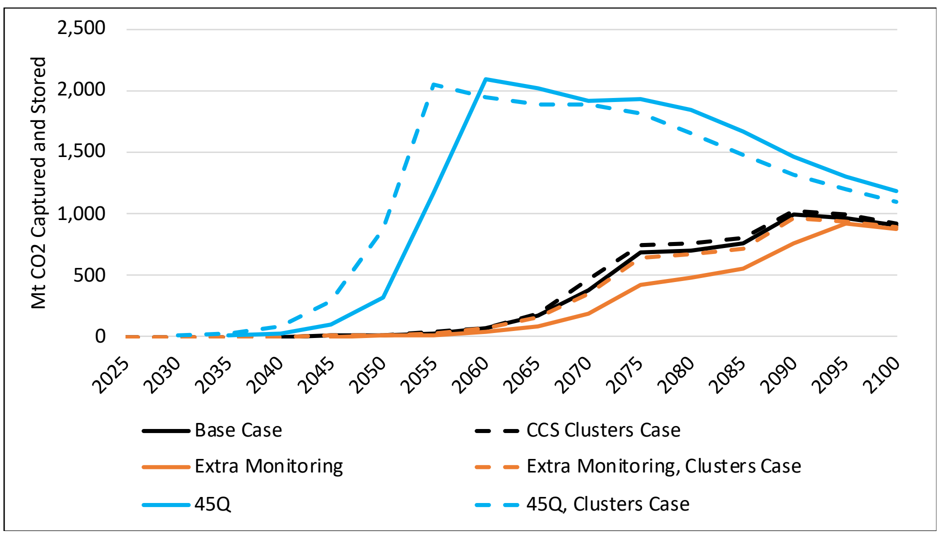

Figure 20. Annual Mt CO_2 captured and stored in the United States for key sensitivities under a scenario that limits warming to 2°C.

9.2. China

Similar to the United States, I explore two 45Q tax credit sensitivities in China – one for the *Base Case*, and one for the *CCS Clusters Case*. For the former, I assume *Base Case* transport and storage costs in all EPPA regions except China, for which I subtract \$50/tCO_2 from the *Base Case* China cost assumption. This results in a net credit of \$34.08/tCO_2 for CCS in China. For the latter, I assume *CCS Clusters Case* transport and storage costs in all EPPA regions except China, for which I subtract

$50/tCO_2$ from the China *CCS Clusters Case* cost assumptions. This results in a net credit of $39.62/tCO_2$ in China. See Table 16 for a breakdown of the transport and storage cost inputs and select results.

Table 16. Breakdown of China transport and storage cost inputs and cumulative CO_2 captured and stored (2020-2100) for key modelling cases and sensitivities.

	Transport and Storage Cost Case	China transport and storage cost ($/tCO_2$)	China Cumulative Gt CO_2 captured and stored (2020-2100)
Uniform Cases	$4/tCO_2$	$4	206
	Reference Case	$10	174
	$45/tCO_2$	$45	1
	$90/tCO_2$	$90	0
Regional Modeling Cases	*Base Case*	$15.92	103
	Clustering	$10.38	173
Base Case Sensitivities with Variable China costs	45Q	$50/tCO_2$ credit on *Base Case* costs	349
CCS Clusters Case Sensitivities with Variable China costs	45Q	$50/tCO_2$ credit on *CCS Cluster* costs	361

So far, I have explored regional modeling cases in China in which transport and storage costs are greater than the *Reference Case* assumption of $10/tCO_2$. Since my results from Chapters 7 and 8 suggest CCS deployment in China is sensitive to transport and storage costs, I felt it would be informative to explore regional sensitivities in which China embraces incentives for CCS that lower these costs below $10/tCO_2$. For ease of comparison with my sensitivities for the United States, I chose to examine a scenario in which China embraces a $50/tCO_2$ tax credit for CCS.

A $50/tCO_2$ credit in China reduces the overall cost of CCS by 47% for coal plants and 15% for gas plants compared to the *Base Case*. This more than triples the amount of CO_2 cumulatively captured and stored there by 2100 compared to the *Base Case*. Under this sensitivity, CCS deployment on coal plants is also hastened by nearly two decades (see Figure 21). China captures and stores 349 Gt CO_2 cumulatively by 2100 under this sensitivity - more than three times the level achieved in the *Base Case*. This is driven entirely by CCS deployment on coal plants, which sees a doubling in cumulative energy generation in China by 2100. Unlike the United States, China does not deploy CCS on natural gas plants in any of the cases I explore.

When CCS clusters and transport networks are assumed in China, a \$50/tCO_2 tax credit reduces the cost of CCS on coal plants by 49% and gas plants by 16% compared to the *CCS Clusters* case. These are very similar cost reductions as the sensitivity without CCS clusters and, as a result, produces similar trends. When CCS clusters are assumed, a \$50/tCO_2 tax credit roughly doubles the amount of CO_2 cumulatively captured and stored by 2100 from173 Gt CO_2 in the *CCS Clusters Case* to 361 Gt CO_2. As before, this is driven almost exclusively by coal plants equipped with CCS. Figure 21 displays the annual CO_2 captured and stored in China through 2100 respectively across the two sensitivities as well as in the *Base Case* and *CCS Clusters Case.*

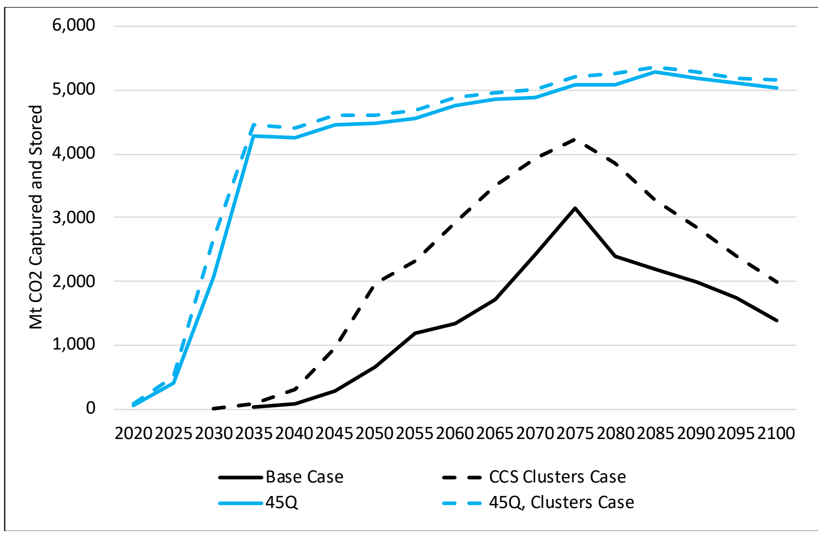

Figure 21. Annual Mt CO_2 captured and stored in China for key sensitivities under a scenario that limits warming to 2°C.

10. Conclusion

10.1. Key Findings

I estimate a practical cost range of \$4 to \$45/tCO_2 for the transport and storage of CO_2 via pipeline. This range represents the range that could be expected across geographic, geologic, and institutional settings. These costs depend on five key sources of variability: transport distance; scale; monitoring requirements; geologic characteristics; and transport cost variability (primarily pipeline capital costs). For the combined cost of transporting CO_2 via ship for offshore storage, I used the low range of the most recent estimates from the Northern Lights Project of €30-55/tCO_2 (\$35 to \$64/tCO_2 USD). I use estimates of cost variability to estimate expected regional differences in transport and storage cost.

In my reference case, where transport and storage costs are assumed to be \$10/tCO_2 uniformly across all regions, results generated using the MIT Economic Projection and Policy Analysis (EPPA) model give 425 Gt CO_2 captured and stored cumulatively from 2020 through 2100. When uniform transport and storage costs are assumed, the model-estimated cumulative CO_2 captured and stored decreases with increasing assumed cost.

The *Base Case*, which captures regional variability by assigning my best estimate of CO_2 transport and storage costs to each of the 18 EPPA regions, results in 290 Gt CO_2 captured and stored cumulatively by 2100. CCS transport networks and storage clusters increase global capacity to capture and store CO_2, with 30% more CO_2 captured and stored cumulatively by 2100 compared to the *Base Case*. Incorporating lower transport and storage costs in Europe – which could occur if projected shipping and storage costs from the Northern Lights Project decline or Europe pursues pipelines instead of ships - results in an additional 8 Gt CO_2 captured and stored cumulatively by 2100 in Europe compared to the *Base Case*.

The frequently used value of \$10/tCO_2 for transport and storage costs is a reasonable assumption in some regions (i.e. the United States, Middle East, Russia, Canada, and Mexico) but not in others (i.e. Europe, Japan, China, Africa, India, etc.). This assumption has a large impact on CCS deployment in regions such as China that have power generation alternatives with low or similar capital costs, making CCS competitiveness more sensitive to increases in transport and storage cost than other regions.

Several transport and storage options should be taken into account when modeling large-scale deployment of CCS in decarbonization pathways. Pipelines are still expected to be the main method of transporting CO_2, and these costs can increase or decrease depending whether the pipeline is assumed to be onshore or offshore or is part of a shared transport infrastructure. Shipping can be cost effective over long distances in regions with limited onshore CO_2 storage capacity, such as in Japan, or that have regulatory barriers to onshore CO_2 transport and storage, such as is seen in Europe.

Cost data are scarce, there is still a significant amount of uncertainty and variability in available CO_2 transport and storage costs, and more analysis is needed to quantify the cost ranges. Deploying CCS at the scale needed to achieve global emissions reduction goals will require buildout of infrastructure to transport and store gigaton-scale levels of CO_2. Qualitatively it is known that CCS transport networks and storage hubs can significantly reduce CO_2 transport and storage costs, and that these will develop in different locations at different paces. It is also known that CO_2 transport and storage costs vary regionally and CCS deployment will be more sensitive to these costs in some regions than others. In addition, regulatory regimes can enable or create barriers for certain CO_2 transport and storage options and can impose or remove significant costs accordingly. More work is needed to quantify the impact of these factors on CO_2 transport and storage costs, especially at the regional level.

Transport and storage costs impact CCS deployment and can assist with its relative competitiveness, but ultimately CCS must compete in a portfolio of other technologies and modeling results hinge on these interactions. Results from sensitivities in the United States and China indicate that transport and storage costs do matter but results are dependent on model structure and input assumptions for other energy generation technologies in the mix (e.g., CCS and nuclear energy capital costs in China being very similar). To better understand the role of different low-carbon technologies in the climate solution set, more efforts similar to this thesis are needed to quantify regional variability in key assumptions across the suite of energy generation options.

10.2. Insight for Policymakers

This thesis offers several takeaways relevant to policymakers interested in understanding the role of CCS in future climate pathways. First, decisionmakers must consider the strengths and limitations of models broadly when analyzing policy levers to achieve desired outcomes. While integrated assessment models (IAMs) are useful tools to understand key system processes and drivers on a macro level, they are not decision-making tools, but rather decision-support tools that help to quantify the policy trade-offs. In addition to a necessary simplification of the reality, all models including IAMs mirror the uncertainties and value judgments inherent to the real-world systems they simulate. While scholars are constantly working to improve and calibrate these tools so they realistically capture key trends, they must always be used in conjunction with insight from other analytical approaches, experts, and stakeholders. Just as a suite of technologies is needed to achieve our climate objectives, so too is a suite of analytical tools and perspectives needed to contribute to more durable, robust, and inclusive knowledge of the solution set.

With regard to models of climate pathways that include the CCS option, policymakers should interpret the results reported in this thesis in the context of the broader energy system. The assumptions underpinning the CCS value chain - such as the cost of CO_2 transport and storage – interact with other energy generation technologies and their underlying assumptions. The competitiveness of CCS varies regionally and depends on the economics of other technologies in the energy mix. Transport and storage costs comprise a key component of the CCS value chain and can influence its overall economic viability depending on key sources of variability discussed in this thesis. However, results should be interpreted with a system-wide view of how these assumptions fit within the broader energy system because they are a byproduct of the model architecture and hinge on input assumptions across all energy generation technologies in the portfolio. For example, my results indicate that CCS deployment is sensitive to transport and storage costs in China because CCS and nuclear energy have similar capital costs there. However, more effort is needed to understand how key input assumptions for other energy generation technologies like nuclear energy impact the overall competitiveness of CCS in different regions and, by extension, the respective roles each solution plays in future climate pathways. Understanding model results in this context will be informative for policymakers considering different policy levers to incentivize the deployment of CCS and other low-carbon technologies.

Keeping the above factors in mind, decisionmakers have a variety of policy options at their disposal that can enable or impede the establishment of CO_2 transport and storage infrastructure and, by extension, CCS deployment broadly. The regulatory environment for CCS varies regionally. Some regions have implemented or proposed policies to facilitate and regulate the transport and storage of CO_2 while others have not established any policies in this space. In the regional sensitivities I explored in Chapter 9, a \$50/tCO_2 tax credit for secure geologic storage (which reflects the value of the 45Q tax credit in the United States) substantially increases CCS deployment. Without the tax credit, there is almost no CCS by midcentury in the United States and substantially less in China (see Figures 20 and 21). Policy support plays an important role in driving the deployment of clean energy solutions like CCS.

In general, regulatory uncertainty tends to suppress the development of CCS and its enabling infrastructure. Project developers are less likely to develop a CO_2 transport, storage, or capture project if they are unclear about the legal barriers, incentives, or protections they face because it exposes them unnecessary risks. Even those regions with established CCS regulatory regimes face uncertainty in many policy areas including long-term liability for CO_2 geologic storage; royalty payments or pore space fees on CO_2 stored underground; the need to consider local and indigenous community concerns in siting and permitting CO_2 pipelines; and policy interactions at different levels of government (e.g. California and the United States policies for CO_2 storage). While other policy uncertainties remain, these are key issues that have been raised by industry players and should be addressed to facilitating CO_2 transport and storage deployment.

As climate ambition ramps up, CCS has the potential to play a key role in the solution set in the power sector and in heavy industry. To achieve net-zero emission targets, CCS is needed both on fossil fuels and for negative emission technologies like BECCS. The establishment of transport and storage infrastructure is critical to achieving the climate benefits offered by CCS. As of 2020, several countries included CCS as part of their commitment to reduce emissions in to achieve global climate targets, including the United States, the European Union, Canada, China, Japan, Australia, and several others. As more CCS projects are deployed, costs are expected to decline due to learning-by-doing and the gains associated with economies of scale. Regions that take initiative to grapple with the dynamics of linking together CO_2 source clusters, transport networks, and storage hubs will stand to see the biggest reductions in CO_2 transport and storage costs and greatest emission reductions associated with CCS. With regard to regional climate policies, China has pledged to become carbon neutral by 2060 and - for the first time in 2020 - included CCS as part of its climate finance discussions, expanding project finance opportunities. Europe, meanwhile, recently ratified amendments to the London Protocol that would allow cross-border transport of CO_2, which previously had faced regulatory hurdles. In the United States, lawmakers have backed bills that would support the buildout of CCS infrastructure, including passage of the USE-IT Act in 2020 and introduction of the SCALE Act in 2021. These followed on the heels of the United States' 2018 expansion of its tax credit for secure geologic storage of CO_2.

The regulatory environment for CCS is growing and crystallizing in many regions. Different policy levers can incentivize the buildout of infrastructure necessary to achieve the climate benefits associated with the large-scale rollout of CCS. Just as the costs of transport and storage varies by region, so too does the suitability and viability of different policy options. Decisionmakers must consider their regional context when evaluating what options are needed or feasible. With the right mix of policies to enable the buildout of transport and storage infrastructure, CCS is one of many tools in the climate solution set that can take us where we want to go.

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