



U.S. DEPARTMENT OF  
**ENERGY**

PNNL-19091

Prepared for the U.S. Department of Energy  
under Contract DE-AC05-76RL01830

# Regional Opportunities for Carbon Dioxide Capture and Storage in China

**A Comprehensive CO<sub>2</sub> Storage Cost Curve and Analysis of the  
Potential for Large Scale Carbon Dioxide Capture and Storage  
in the People's Republic of China**

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December 2009



**Pacific Northwest**  
NATIONAL LABORATORY

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# **Regional Opportunities for Carbon Dioxide Capture and Storage in China**

## **A Comprehensive CO<sub>2</sub> Storage Cost Curve and Analysis of the Potential for Large Scale Carbon Dioxide Capture and Storage in the People's Republic of China**

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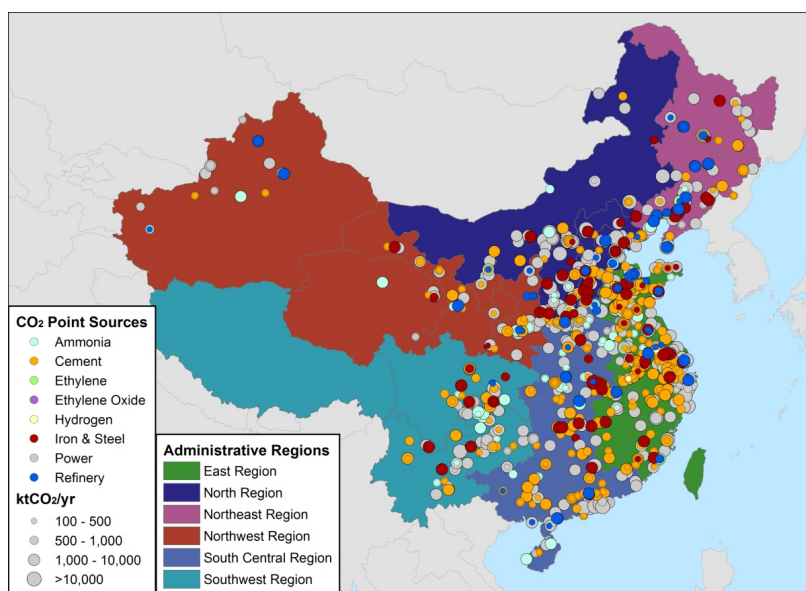
## Executive Summary

To date, much of the discussion about China's options for addressing climate change have focused almost exclusively on coal – the nation's large indigenous reserves, and its heavy and increasing use in powering China's fast-growing economy. This discussion of China's reliance on coal coupled with the need to reduce global greenhouse gas emissions is too often framed as an all-or-nothing proposition which has created a false dichotomy suggesting that China must choose between either continuing to use domestic coal and bearing the environmental consequences, or forgoing cheap domestic reserves and bearing the economic consequences. This study demonstrates for the first time the significant potential for carbon dioxide capture and storage (CCS) technologies to deploy in China, presenting the possibility of a third option that supports continued economic growth with coal while safely and securely reducing carbon dioxide (CO<sub>2</sub>) emissions to the atmosphere. As such, CCS may offer a valuable option for China as part of a large and diverse portfolio of advanced clean energy and climate change mitigation technologies.

The research reported here is the result of an unprecedented and highly productive five-year collaboration between researchers in the United States and China. Together this international team of researchers has documented in this report that there is significant potential for CCS technologies to deploy in China and to deliver deep, sustained and cost-effective emissions reductions over the course of this century and potentially beyond.

This study identified 1,623 large stationary CO<sub>2</sub> point sources in China that each emit at least 100,000 metric tons (tonnes) of CO<sub>2</sub> per year. Combined annual CO<sub>2</sub> emissions from these large stationary power and industrial facilities are estimated at over 3,890 million tonnes (MtCO<sub>2</sub>), which represents 64 percent of the total annual CO<sub>2</sub> emissions from all aspects of the Chinese economy. These 1,623 large stationary CO<sub>2</sub> emissions sources include:

- 629 power plants (94% of them coal-fired units) together emitting more than 2,810 MtCO<sub>2</sub> per year, with coal-fired units accounting for over 98% of this total.
- 994 large non-power industrial CO<sub>2</sub> sources that emit approximately 1,080 MtCO<sub>2</sub> per year. The majority (56%) of these are cement plants with the remainder being ammonia plants, iron and steel facilities, and petrochemical refineries.

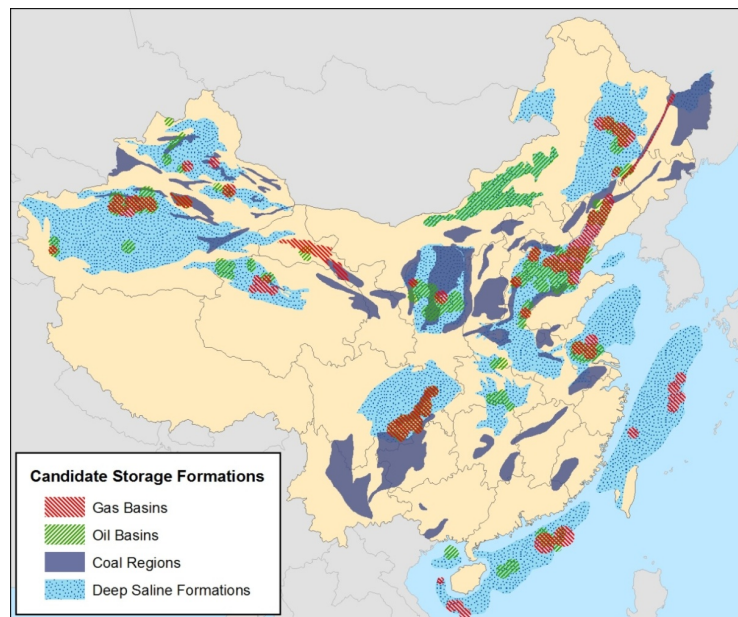


**Figure ES.1** Map of Large CO<sub>2</sub> Point Sources by Type, Size, and Administrative Region

- The 100 largest sources are responsible for nearly one-third of the total annual emissions from these 1,623 facilities and the 500 largest CO<sub>2</sub> emitters are responsible for 3,060 MtCO<sub>2</sub>/yr or 79% of the total emissions from the set.
- As can be seen from Figure ES.1, the majority of the large, stationary CO<sub>2</sub> point sources are concentrated along the more heavily developed coastal zones of China, with 58% of all of the sources being located within the East and South Central regions.

This report and underlying study establish that China has a large and geographically dispersed theoretical deep geologic CO<sub>2</sub> storage capacity in excess of 2,300,000 MtCO<sub>2</sub> in onshore basins with an additional 780,000 MtCO<sub>2</sub> potentially in relatively near offshore basins as depicted in Figure ES-2. Deep saline-filled sedimentary basins account for over 99% of the total calculated storage capacity. There are:

- 16 onshore deep, saline-filled sedimentary basins (DSFs) with an estimated CO<sub>2</sub> storage capacity of 2,288,000 MtCO<sub>2</sub>, plus additional capacity in 9 offshore basins estimated at 779,000 MtCO<sub>2</sub>. Total CO<sub>2</sub> storage capacity across all DSFs is estimated at over 3 billion tonnes of CO<sub>2</sub>.
- 16 onshore and 3 offshore depleted oil basins with potential for enhanced oil recovery have a total estimated CO<sub>2</sub> storage capacity of 4,800 MtCO<sub>2</sub> – of which 4,600 MtCO<sub>2</sub> is found onshore.
- 45 major coal basins with total CO<sub>2</sub> storage capacity of approximately 12,000 MtCO<sub>2</sub> in deep, unmineable coal seams with potential for CO<sub>2</sub>-driven enhanced coal bed methane recovery.
- 13 major onshore and 4 major offshore gas basins assessed in this study, which combine to offer more than 5,100 MtCO<sub>2</sub> in total estimated CO<sub>2</sub> storage capacity.



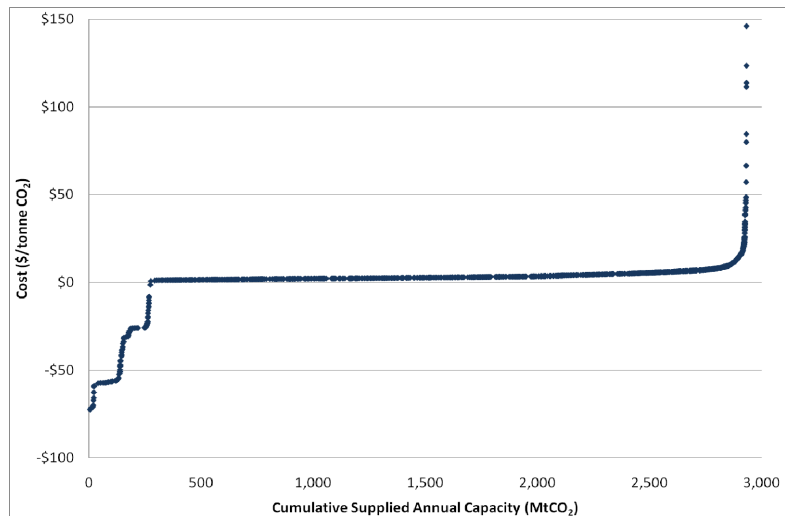
**Figure ES.2** Map Showing the Combined Location and Extent of Candidate Geologic CO<sub>2</sub> Storage Formations Analyzed in This Study

A central aspect of the research presented here was to model the economic competition between this large number of stationary CO<sub>2</sub> point sources and China's large theoretical CO<sub>2</sub> storage capacity in deep geologic reservoirs. Key conclusions from this source-reservoir matching analysis include:

- Most large stationary CO<sub>2</sub> point sources in China are in relatively close proximity to at least one candidate deep geologic CO<sub>2</sub> storage reservoir:

- 54% have a candidate storage formation in the immediate vicinity;
  - 83% have at least one storage formation within 80 km (50 miles); and
  - a full 91% have the potential to reach a candidate storage formation within 160 km (100 miles).
  - Variations do occur from region to region across China with large numbers of CO<sub>2</sub> sources in the industrialized coastal areas having less access to abundant onshore CO<sub>2</sub> storage capacity than sources in the interior regions.
- The economic implications of pairing China’s fleet of large CO<sub>2</sub> point sources with its abundant storage capacity resource are revealed through the cost curve analyses documented in this report. Key findings from this engineering and economic modeling of how CCS technologies might deploy in China indicate that:

- Most of the large CO<sub>2</sub> emissions sources in China should be able to transport and geologically store their CO<sub>2</sub> for decades – and potentially a century or more – at costs between \$2 and \$8/tCO<sub>2</sub>. These costs include CO<sub>2</sub> transport via pipeline, site characterization, injection, measurement, monitoring, and verification (MMV), plus production and CO<sub>2</sub> recycling costs for enhanced oil recovery and enhanced coalbed methane recovery projects. Costs associated with CO<sub>2</sub> capture and compression are not included in these estimates.



- The CO<sub>2</sub> storage resource of China is robust and able to meet the demand from the majority of China’s large CO<sub>2</sub> sources at these costs over decades of large-scale deployment, even if the ultimately accessible storage resource proves to be considerably less than the 2,300,000 MtCO<sub>2</sub> estimated here.

**Figure ES.3** Reference Case Cost Curve for CO<sub>2</sub> Transport and Storage in China

- There appears to be a number of potential opportunities for low and even negative cost CO<sub>2</sub> transport and storage in candidate value-added CO<sub>2</sub> storage formations such as oil fields and coal seams with enhanced recovery potential from CO<sub>2</sub> injection. However, these options remain relatively limited and further evaluation is needed to confirm the timing of availability for CO<sub>2</sub> storage as well as the expected cost and performance characteristics of these formations.
- The vast majority of the 1,623 large CO<sub>2</sub> point sources in China are likely to rely heavily if not exclusively on high capacity and widely distributed deep saline sedimentary formations.
- There is significant variation in storage demand and resulting costs from region to region in China. In particular, this report documents a number of large CO<sub>2</sub> sources with limited access to adequate storage capacity in nearby onshore basins. These are predominantly located in the coastal regions and further study of the potential and costs for storage into nearby offshore basins will be valuable for these areas.

This work represents a first order assessment of the potential for CCS technologies to deploy in China and provides a solid foundation on which to build additional understanding in this new and complex area of research. Many initial questions have been answered by this analysis. In particular, this analysis demonstrates that CCS technologies could play a significant and sustained role in delivering cost effective CO<sub>2</sub> emissions reductions for China over the course of this century. This is critical for the continued economic development of China as well its trading partners, and those working to establish a robust, durable and viable framework for reducing global emissions of greenhouse gases. While a portfolio of technological and other approaches will be needed to significantly reduce greenhouse gas emissions in China and throughout the world, the availability of CCS as a meaningful and cost effective CO<sub>2</sub> mitigation option for China could reduce costs and allow for continued economic development in this important region.



## Acknowledgments

This report and its underlying analyses are the result of a strong and unprecedented collaboration between researchers in the U.S. and China and are intended to provide an initial examination of the potential to deploy carbon dioxide capture and storage (CCS) technologies within the People's Republic of China for the purposes of climate protection. Funding for this work was provided by the U.S. Department of Energy through the U.S./China Energy and Environmental Technology Center and Leonardo Technologies, Inc. Additional funding and support has been provided through the Global Energy Technology Strategy Program led by the Joint Global Change Research Institute, a partnership between the Pacific Northwest National Laboratory, Battelle, and the University of Maryland. This research report is a product of the *Regional Opportunities for Carbon Dioxide Capture and Storage in China* project, one of a select number of multi-national CCS projects worldwide to be recognized by the Carbon Sequestration Leadership Forum.



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# 1.0 Introduction

The People's Republic of China is the most populous country in the world and has been experiencing tremendous economic and industrial growth (Marland et al. 2008). China's population has doubled over the past four decades and now exceeds 1.3 billion people; economic growth has averaged 9.8% annually since 1980 (IEA 2007). The country has abundant domestic coal reserves (the third largest in the world) that power the economy, supplying an estimated 69 percent of China's primary energy consumption (EIA 2006). China is the largest coal producer in the world, and the bulk of anthropogenic carbon dioxide emissions result from coal combustion.<sup>1</sup> Electricity generation in 2005 was greater than 2.4 trillion kilowatt-hours, making China the second largest power producer behind only the United States (EIA 2007), and recent growth rates have been unprecedented, adding 105 gigawatts of capacity in 2006 alone (IEA 2007). China is also the global leader in the production (and consumption) of such carbon-intensive commodities as steel, ammonia, and cement.

It is estimated that China's fossil-fuel carbon dioxide (CO<sub>2</sub>) emissions increased some 66% during the relatively short period between 2000 and 2005 (Marland et al. 2008), and several recent studies have concluded that China overtook the United States as the largest global emitter of CO<sub>2</sub> in 2006 (NEEA 2008; Gregg et al. 2008). While historic and per-capita CO<sub>2</sub> emissions remain low compared to more developed countries, the rapid development in China along with the heavy reliance on domestic coal resources means that, left unchecked, overall CO<sub>2</sub> emissions will continue to rise significantly in the coming decades. The International Energy Agency's Reference Scenario projects that China's energy-related CO<sub>2</sub> emissions will be 35% higher than the United States' by 2015 and 66% higher by 2030 (IEA 2007).

For the world to take serious action against increasing concentrations of greenhouse gases in the atmosphere and their associated climate impacts, we must collectively examine the potential for reducing CO<sub>2</sub> and other greenhouse gas emissions in all major regions of the world. While a number of complementary approaches will be necessary to slow the increase in atmospheric greenhouse gas concentrations, analyses suggest that carbon dioxide capture and storage (CCS) technologies could provide significant economic benefits when included in the overall portfolio of climate change mitigation options (Metz et al. 2005). Over the past several years, research into the potential, costs, and feasibility of CO<sub>2</sub> capture and geologic storage has increased significantly throughout the world. Initial studies on the large stationary CO<sub>2</sub> point sources, geologic CO<sub>2</sub> storage resources, and deployment costs have been performed for regions including the United States and Canada (Dahowski et al. 2005), Europe (Wildenborg et al. 2005), Australia (Bradshaw et al. 2004), India (Holloway et al. 2008) and elsewhere. These studies have contributed to the understanding of the potential for CCS technologies to deploy widely in these regions and their ability to help mitigate global climate impacts. They have also contributed to the development of significant research programs designed to enhance the technical community's understanding of the costs and risks associated with CCS and prepare the suite of CCS technologies for a broader, commercial-scale deployment.

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<sup>1</sup> CO<sub>2</sub> emissions from coal use accounted for 98.7% of China's total CO<sub>2</sub> emissions in 1950. However as the transportation sector has grown in China the overall share of CO<sub>2</sub> emissions from coal use has declined to approximately 73.7% in 2005 although net emissions from coal use has increased steadily over this period (Marland et al. 2008).

However, until now there have been no comparable, comprehensive studies of the CO<sub>2</sub> sources and candidate geologic storage reservoirs in China. This project was designed to be the first of its kind study to catalog and examine characteristics of large anthropogenic CO<sub>2</sub> sources, candidate geologic storage reservoirs, and to analyze opportunities for CCS deployment in this region. This first-order assessment is intended to illustrate the potential for CCS technologies to be deployed in China, linking the nation's large and growing industrial CO<sub>2</sub> source fleet with available geologic CO<sub>2</sub> storage reservoirs capable of storing CO<sub>2</sub> safely over significant time scales, and to present an initial estimate of costs for CO<sub>2</sub> transport and storage. The analysis is intended to represent a first step towards a more comprehensive understanding of China's potential opportunities to utilize CCS as a means of cost-effectively controlling CO<sub>2</sub> emissions.

This report presents the resulting compilation of large stationary CO<sub>2</sub> point sources and the estimation of their emissions, along with the identification and evaluation of theoretical basin-scale geologic storage potential. This is followed by a description of data and methodology for estimating costs of various CCS system components. Finally, cost curves for CO<sub>2</sub> transport and storage for China and regions thereof are presented, along with a select number of sensitivity analyses to provide further insight into the robustness of the CO<sub>2</sub> storage resource and the sensitivity of the resulting cost estimates to a variation in key parameters.

While this analysis fills a void in the current literature by taking a first order look at the potential for geologic CO<sub>2</sub> storage in China, the very emerging nature of the knowledge and focus on CCS in China, coupled with data availability issues that are common throughout much of the world, have necessitated the use of simplifying assumptions. These are based in part upon extrapolation of knowledge and experience gained in the U.S. and other parts of the world to fill in gaps where China-specific data are limited. Additional research is needed, and many areas for follow-on evaluation are proposed based on this initial study. However, this analysis has helped to demonstrate the ability of CCS to deploy broadly within China and provide significant value as a climate change mitigation strategy. CCS technologies are essential to the development of near-zero emission coal technology, and may help China preserve the economic and societal benefits of continuing to utilize its vast domestic coal resource, even in a carbon-constrained world. This study will hopefully spur additional research, critical thinking, policy action, and proactive steps towards reducing greenhouse gas emissions to mitigate the impacts of global climate change.



## 2.0 Large CO<sub>2</sub> Point Sources in China

There are many different types of anthropogenic CO<sub>2</sub> emissions sources in China, many of which are growing as industrialization and urbanization progress and overall living standards increase. Growth in the production of a number of key carbon-intensive commodities is required to meet these demands including increased cement, iron and steel production, in addition to growing needs for electric power and transport fuels.

The focus within this project is on the large, stationary source CO<sub>2</sub> emitters, such as power plants, cement kilns, steel mills, and petroleum and chemical refineries. The goal has been to compile an initial dataset that represents the vast majority of large point sources that emit at least 100,000 tonnes of CO<sub>2</sub> per year. Sources smaller than these are considered unlikely to be economic to employ CO<sub>2</sub> capture technologies, particularly in the nearer term.<sup>1</sup> As a result, the analysis does not consider all anthropogenic CO<sub>2</sub> emissions, and specifically not those from small industrial CO<sub>2</sub> point sources (those emitting less than 100,000 tCO<sub>2</sub>/y), transportation, direct energy use in commercial and residential building sectors, land use, agriculture, and similar activities. Nevertheless, the catalogued emissions from these large stationary CO<sub>2</sub> point sources together represent 64 percent of the total CO<sub>2</sub> emissions for China in 2005 as reported by Boden et al. (2009). The methods and results presented here on documenting the large stationary CO<sub>2</sub> point sources in China expand on the work initially published by Dahowski et al. (2009) and Li et al. (2009).

### 2.1 Data Challenges

Given that China is growing at such a phenomenal rate and that data issues make it difficult to obtain fully complete and accurate data on industrial sectors, it was not possible within the time and budget constraints of this project to perform a fully detailed and current accounting of all large CO<sub>2</sub> point sources. Examples of some of the policies driving rapid changes for industrial plants in China became more widely recognized as China prepared to host the 2008 Summer Olympic Games.<sup>2</sup> Therefore, the focus was to compile the most detailed and accurate accounting of the key industries possible subject to data constraints. Further, it was not possible to examine some key new industries that are beginning to develop in China, such as coal-to-liquids production. A critical continuing research need is therefore to update the CO<sub>2</sub> source data with more recent data as they become available. Nevertheless, the current compilation of CO<sub>2</sub> point sources resulting from this study provides a solid foundation for the development of cost curves for CO<sub>2</sub> transport and storage in China.

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<sup>1</sup> This 100,000 tonne/yr threshold has been applied in similar studies for other regions of the world, including North America (see Dahowski et al. 2005), Europe (see Wildenborg et al. 2005), and others.

<sup>2</sup> Additionally, there has been a push by the Central Government over the last several years to shut down thousands of the smaller, less efficient power and other industrial plants and replace them with a smaller number of larger and more efficient plants. There have also been reports that up to 20% of the power plants in China are illegal, built to meet local demands but not authorized or recognized and reported by the Central Government (Oster 2006). Such actions all combine to make it difficult to compile a thorough and updated accounting of large CO<sub>2</sub> point sources in China.

## 2.2 Building the CO<sub>2</sub> Point Source Database

The following sections describe the process applied for compiling the data on the large CO<sub>2</sub> point sources in China, and estimating their emissions.

### 2.2.1 Electric Power Sector

Given the tremendous growth rate of China's electric power sector, and the scale of emissions from power generation fueled predominantly by coal, an extra effort was made to ensure that the sources from this sector were as current as reasonably possible. To accomplish this, the World Electric Power Plants (WEPP) Asia Database was used with data current to 2007 (WEPP 2007). For China, WEPP contains data on 6,060 electric power generating units of all fuel types (including coal, gas, oil, renewables, nuclear and other non-fossil fuels) ranging in size from 0.007 to 7400 MW, in a variety of stages including planning, construction, operation, and retirement.

The method applied to develop plant level data on large CO<sub>2</sub>-emitting power plants was as follows. Because for this study we are interested only in those plants that emit significant CO<sub>2</sub>, any non-fossil-fueled generating units (e.g., hydro, nuclear, solar, wind) as well as those very small fossil units with capacities less than 10 MW, were filtered out of the set. Additionally, due to the greater uncertainty associated with planned plants, only the units whose status was listed as "operating" were selected. As a result, this provided a database of 2,035 fossil-fueled units that were operating as of 2007. CO<sub>2</sub> emissions for each of these units were estimated based on reported fuel and technology type, capacity, and assumptions for capacity factor and CO<sub>2</sub> emissions factors shown in Table 2.1.

**Table 2.1.** Capacity Factor and CO<sub>2</sub> Emissions Factor Assumptions for Power Generation

<b>Fuel Class &amp; Technology</b>	<b>Capacity Factor</b>	<b>Emissions Factor, g CO<sub>2</sub>/kWh</b>
Coal, sub-critical	0.85	1000
Coal, supercritical	0.85	920
Gas	0.4	400
Oil, steam	0.7	500
Oil, comb. turbine or internal combustion	0.4	500

Units were then removed that didn't meet the 100,000 tCO<sub>2</sub>/yr threshold, resulting in 1,984 units with combined estimated annual CO<sub>2</sub> emissions of 2,811 MtCO<sub>2</sub>. Coal-fired units represent the overwhelming majority of these, accounting for 94% of the number and a full 98.5% of the total estimated emissions. Finally, these generating unit data were aggregated to the plant level for 629 different plants.

### 2.2.2 Other CO<sub>2</sub> Emitting Sectors

The other industrial sectors examined within the scope of this study include: cement, iron & steel, petroleum refineries, ammonia, ethylene, ethylene oxide, and hydrogen. Initial data for these sectors originated from the worldwide inventory of large CO<sub>2</sub> sources as compiled and frequently updated by the

IEA Greenhouse Gas R&D Programme (IEA GHG 2002a, 2006) plus recent efforts by Liu et al. (2006a). These data for China provided a starting point from which to move forward and gather additional data. The process for all of these sectors involved locating available information from a variety of sources, including industry, company, and enterprise databases and websites, and product databases. Enterprise locations (city and province) were identified from these databases and web searches, and corresponding latitude and longitude coordinates were assigned based on city center of each location. Emissions were estimated based on available plant capacities and productivities, as noted below:

$$ECO_2 = EF \times P_1 \times A \times T$$

where  $ECO_2$  are the estimated annual CO<sub>2</sub> emissions,  $EF$  is the appropriate CO<sub>2</sub> emissions factor,  $P_1$  is the productive capacity,  $A$  the productive rate, and  $T$  the full time load in hours. For instances where only production values were available, this calculation method reduces to:

$$ECO_2 = EF \times P_2$$

where  $P_2$  represents annual production for the specified source. The emissions factors applied to each of these sectors are shown in Table 2.2. Though the data sources vary, the CO<sub>2</sub> source estimates for the non-power sectors are estimated to be current to at least 2004, some more recent. Results for these non-power sectors indicate that there are 994 large (100+ ktCO<sub>2</sub>/yr) plants, emitting a combined 1,081 MtCO<sub>2</sub>/yr. The majority (56%) are cement plants, followed by ammonia plants, iron and steel mills, and refineries.

**Table 2.2.** Emission Factors (Ton CO<sub>2</sub> per Ton of Output) by CO<sub>2</sub> Source Type

Sector	CO <sub>2</sub> Emissions Factors			
Cement	0.882 <sup>(a)</sup>	0.867 <sup>(b)</sup>	1.111 <sup>(c)</sup>	1.102 <sup>(d)</sup>
Steel & Iron		1.270		
Refineries		0.219		
Ethylene		2.541		
Ammonia		3.800		
Ethylene Oxide		0.458		
Hydrogen		6.150		
a	Dry method1			
b	Dry method2			
c	Wet method1			
d	Wet method2			

### 2.2.3 Quality Assurance

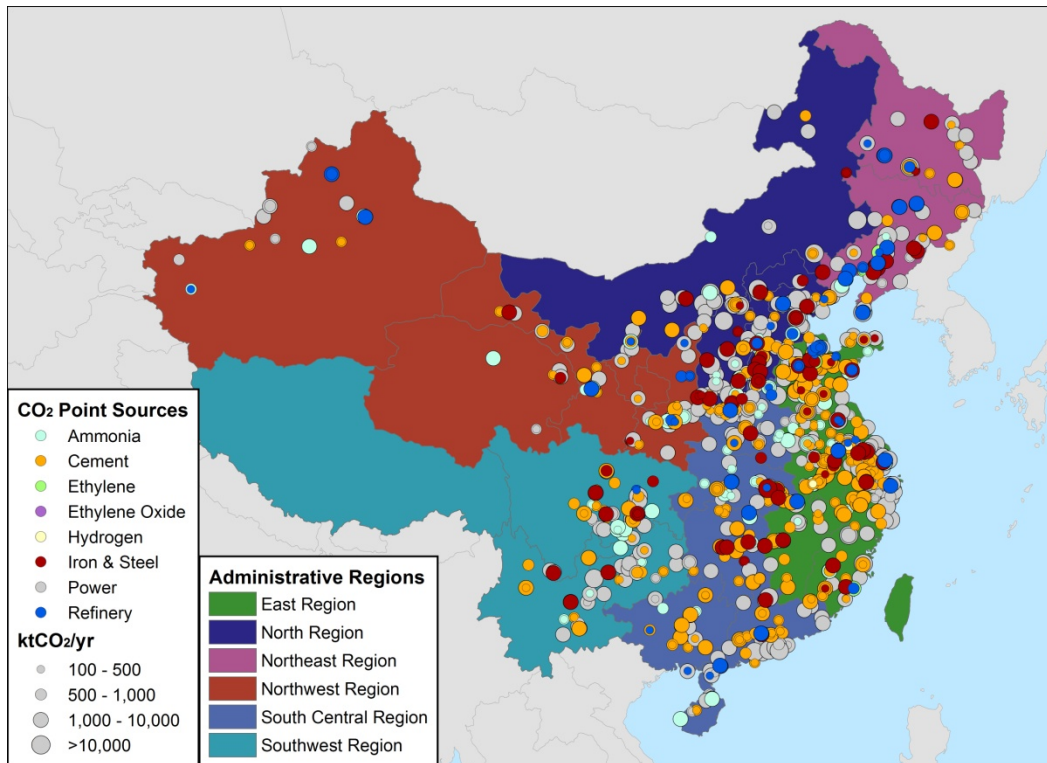
Quality assurance was performed on the resulting data and emissions estimates for the power sector by comparing the results to the estimates developed and published by Carbon Monitoring for Action (CARMA 2007). Resulting emissions estimates were considered to be well within reasonable error

bounds considering the differing methodologies and approaches employed. However, it was quickly determined that the accompanying coordinate data for many of the Chinese power plants contained significant inaccuracies (e.g., geographic coordinate data that placed a given facility in the wrong province), requiring significant reconciliation. This arduous task was accomplished by checking each of these points and their stated city and province with a global coordinate database as well as with significant searching and visual inspection with Google Earth. Similar quality assurance was performed on the other point source data though with significantly fewer issues. As a result of the time invested in improving these data, the resulting CO<sub>2</sub> sources dataset is largely representative of China's large industrial CO<sub>2</sub> point sources and provides a strong basis for this analysis.

## 2.3 Characteristics of Large CO<sub>2</sub> Point Sources in China

Figure 2.1 is a map showing the locations of the resulting 1,623 CO<sub>2</sub> point sources that each emit at least 100,000 tonnes of CO<sub>2</sub> per year. The combined annual CO<sub>2</sub> emissions from these sources are estimated at over 3,890 MtCO<sub>2</sub>. The majority of the sources are concentrated along the coastal zones, with 58% of the sources being located within the East and South Central regions. Within China, 35% of all the CO<sub>2</sub> emitted by these large point sources is produced in the East region; 21% each in the North and South Central regions; 8% each in the Northeast and Southwest regions; and 6% in the Northwest region.

Table 2.3 identifies the individual provinces, municipalities, and autonomous regions comprising each of these six administrative regions, along with total area and population estimates (NBS 2008) and resulting number of large CO<sub>2</sub> point sources and their total annual emissions. A closer examination of these figures provides a more complete picture of the regional distribution of population density and industrial activity and related CO<sub>2</sub> emissions. In addition to having the largest number of large CO<sub>2</sub> point sources and highest resulting emissions, the East region also leads in emissions density from these large sources as well as total population and population density. The East is second in per capita emissions from the identified large CO<sub>2</sub> point sources, trailing only the North, which is second in total annual emissions. The South Central is also a highly industrialized region and has the second highest population of the six regions; it also has the second highest CO<sub>2</sub> emissions density. The Northeast and Southwest regions have very similar CO<sub>2</sub> source and emissions numbers, yet the Southwest is three times larger and most industrial activity occurs in the easternmost part of the region, with the sparsely populated Tibetan Plateau comprising much of the remainder. The largest of China's administrative regions, spanning over 3 million square kilometers, is the Northwest region which has the lowest number of CO<sub>2</sub> sources as well as annual emissions, emissions density, and population.

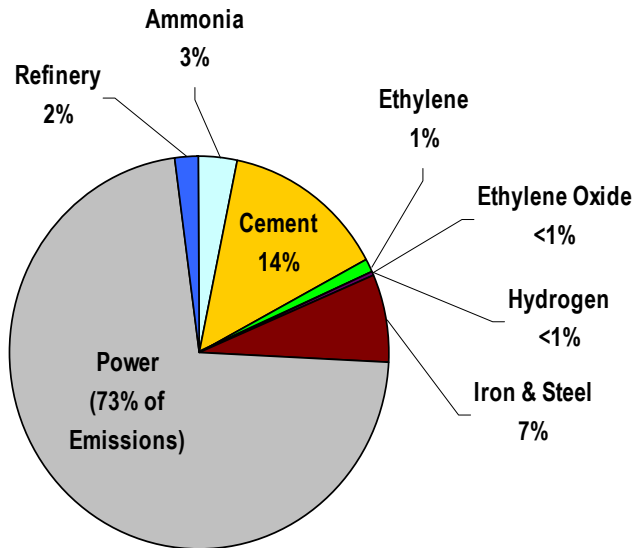


**Figure 2.1.** Map of Large CO<sub>2</sub> Point Sources by Type, Size, and Administrative Region

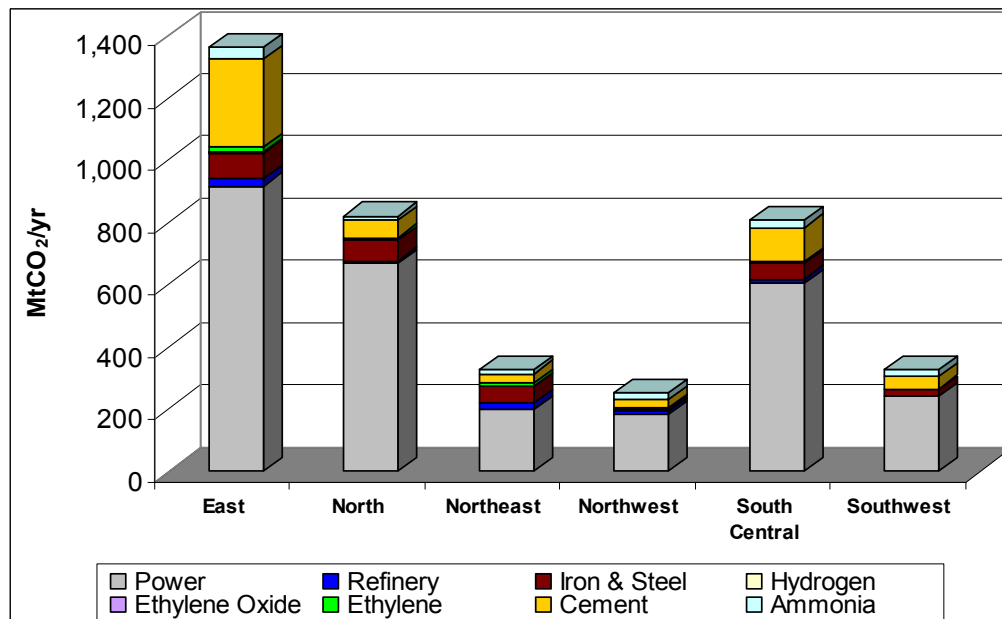
**Table 2.3.** Provinces, Municipalities, and Autonomous Regions and Combined Area, Population, and CO<sub>2</sub> Emissions by Administrative Region

Administrative Region	Provinces, Municipalities, Autonomous Regions	Area, km <sup>2</sup>	Population (million, 2007)	CO <sub>2</sub> Sources	MtCO <sub>2</sub> /y
East	Anhui, Fujian, Jiangsu, Jiangxi, Shandong, Shanghai, Zhejiang	792,741	379.8	588	1,361.5
North	Beijing, Hebei, Inner Mongolia, Shanxi, Tianjin	1,555,105	154.9	254	819.9
Northeast	Heilongjiang, Jilin, Liaoning	787,300	108.5	159	326.9
Northwest	Gansu, Ningxia, Qinghai, Shaanxi, Xinjiang	3,107,900	96.2	129	250.7
South Central	Guangdong, Guangxi, Hainan, Henan, Hong Kong, Hubei, Hunan, Macau	1,014,033	372.3	349	805.9
Southwest	Chongqing, Guizhou, Sichuan, Tibet, Yunnan	2,365,700	195.0	144	327.1

Power generation accounts for 73% of the total annual CO<sub>2</sub> emissions from all of these cataloged sources, and as noted earlier the vast majority of the power sector emissions are from coal-fired units. Cement plants contribute 14% of the total annual CO<sub>2</sub> emissions, as shown in Figure 2.2, followed by Iron & Steel, Ammonia, Refineries, Ethylene, Ethylene Oxide, and Hydrogen. Figure 2.3 provides a summary of CO<sub>2</sub> emissions from these sources by both region and sector, highlighting the variation in sectoral contribution to emissions throughout the different parts of China.

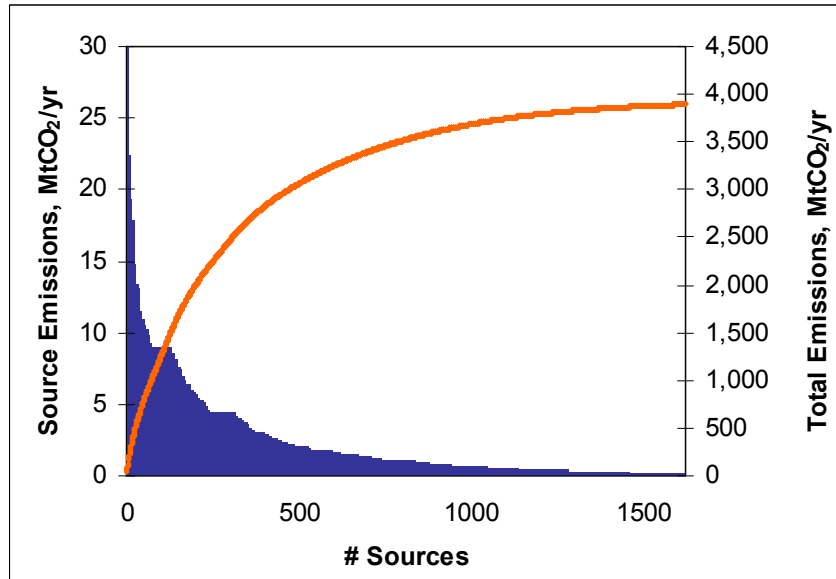


**Figure 2.2.** Contribution of Large Point Sources in Each Sector to Overall Total CO<sub>2</sub> Emissions



**Figure 2.3.** CO<sub>2</sub> Emissions by Sector and Region (MtCO<sub>2</sub>/yr)

Figure 2.4 presents the size distribution of the entire set of 1,623 large CO<sub>2</sub> point sources in China that were cataloged in this study, and their contribution to total emissions. The 100 largest sources are responsible for nearly one-third of the total annual emissions and the 500 largest CO<sub>2</sub> emitters are responsible for 3,060 MtCO<sub>2</sub>/yr or 79% of the total emissions from the set.



**Figure 2.4.** Size Distribution of 1,623 Large CO<sub>2</sub> Point Sources (Blue Bars) and Cumulative Emissions (Line)





## 3.0 Candidate Geologic CO<sub>2</sub> Storage Reservoirs

This study evaluates four types of geologic reservoirs present within China that have been identified as candidates for the long-term storage of CO<sub>2</sub> – deep saline-filled sedimentary formations, depleted gas basins, depleted oil basins with potential for CO<sub>2</sub>-enhanced oil recovery (EOR), and deep unmineable coal seams with potential for enhanced coalbed methane recovery (ECBM). The focus is primarily on onshore basins at this time although some initial data have been collected and reported for offshore basins.

The following sections describe the data and methodologies used to estimate and map the theoretical CO<sub>2</sub> storage capacities within these types of geologic reservoirs. The methods and results presented here on documenting the candidate geologic CO<sub>2</sub> storage reservoirs in China expand on the research initially published by Li et al. (2009) and Dahowski et al. (2009).

### 3.1 Deep Saline Sedimentary Formations

Deep saline-filled sedimentary formations (DSFs) are typically characterized as sandstones or carbonate rocks, and are filled with waters too saline to serve as potential drinking or irrigation sources. DSFs tend to be the largest, most widely distributed, and highest capacity potential geologic CO<sub>2</sub> storage formations, and are capable of retaining CO<sub>2</sub> via dissolution, hydrodynamic trapping, residual pore trapping and, to varying extents, mineralization (Metz et al. 2005). While most, if not all, of these storage mechanisms will likely play a role within a given DSF over time, to provide a conservative estimate of theoretical capacity this study will focus on the dissolution trapping potential of each basin.

Data on the spatial extent of the major sedimentary basins in China were derived primarily from geospatial data published by the United States Geological Survey (2000). These data were supplemented by higher-resolution basin boundaries and locations of additional basins taken from the Atlas of Oil and Gas Basins in China (Li and Lu 2002). Figure 3.1 shows the 27 major sedimentary basins evaluated for this study, comprised of 17 onshore and 10 offshore basins.

Because there are few high-resolution datasets on the characteristics of these large basins as potential CO<sub>2</sub> storage reservoirs, capacity estimation focused on a basin level approach similar to those used in other large regional- and national-scale CO<sub>2</sub> storage capacity estimation analyses (e.g., Dahowski et al. 2005, Wildenborg et al. 2005, Bradshaw et al. 2004, Holloway et al. 2008). As with other such first-order estimates, the storage capacities evaluated here for China are intended only to provide a starting point for finer-resolution analyses as additional supporting data become available via further investigation. In the absence of detailed descriptions of parameters including basin geometry, fractional lithology, porosity and geochemistry, storage capacity was evaluated using an approach that incorporates both volumetric and solubility parameters. First, basin geometry was evaluated to calculate bulk basin volume. Based on experiential knowledge of these basins, general basin-wide porosity and net sand thickness values were assigned, and applied to each basin to estimate total basin pore volume for depths greater than 800-1000 meters (to ensure pressures required to maintain supercriticality of injected CO<sub>2</sub> within the storage formation).



**Figure 3.1.** Map of Major Sedimentary Basins in China As Evaluated In This Study

Next, using data derived by Brennan and Burruss (2006) on CO<sub>2</sub> solubilities at various salinities, each basin was evaluated for its capacity to store injected CO<sub>2</sub> via dissolution trapping. This implies an assumption that the formation is expected to return to 100% residual water saturation once the storage system has reached equilibrium. Although it may take hundreds of years after the end of injection for the system to reach its new equilibrium, the assumption was selected specifically to result in theoretical CO<sub>2</sub> storage capacity values on the conservative end of the spectrum, since there is certainly the possibility for long-term retention of free-phase CO<sub>2</sub> stored via hydrodynamic trapping (Metz et al. 2005). Also, because of the nature of residual gas trapping of CO<sub>2</sub>, which effectively strands some CO<sub>2</sub> in pore space by physically separating it from the larger free-phase plume and reducing its chances of dissolving in the formation waters, it is not feasible for every molecule of injected CO<sub>2</sub> to ever dissolve completely in the resident formation waters, even after those waters have re-infiltrated the entire formation. However, given the high degree of uncertainty in the gross average values assumed for each basin's thickness and porosity, and by way of accounting for the gap between theoretical storage capacity (as presented by analyses such as this) and technically achievable capacity in the field, the authors have chosen to utilize a 100% residual water saturation assumption to maintain the conservative nature of these basin scale theoretical storage capacity estimates. The Brennan and Burruss analysis presents solubilities for two end-member salinities: zero and four molal NaCl solutions. Our analysis assumes that formation waters contain total dissolved solids equivalent to a 4m NaCl solution. This assumption of highly saline waters, rather than fresher waters, was again employed to result in more conservative capacity estimates. As Table 3.1 demonstrates, relaxing the saturation and salinity constraints would result in an overall increase in storage capacity estimates of an order of magnitude or more.

**Table 3.1.** Brennan & Burruss CO<sub>2</sub> Solubilities per Bulk Pore Volume for Zero and Four Molal NaCl Equivalent Solutions

Salinity	Residual water saturation	Density of free-phase CO <sub>2</sub> (kg/m <sup>3</sup> )	Storage Potential (kgCO <sub>2</sub> /m <sup>3</sup> of pore volume)
0m dissolved solids (fresh water)	0%	604	604
	5%	604	580
	50%	604	330
	75%	604	190
	100%	604	51
4m NaCl equivalent solution	0%	604	604
	5%	604	580
	50%	604	320
	75%	604	170
	100%	604	28

*from Brennan & Burruss, 2006*

Total theoretical CO<sub>2</sub> storage capacities for each basin were estimated by applying the Brennan and Burruss specific storage capacity shown above (assuming 100% residual water saturation and 4m NaCl equivalent total dissolved solids concentration) to the calculated pore volume for each basin. Therefore the resulting theoretical CO<sub>2</sub> storage capacity estimates are intended to represent conservative, and potentially more achievable, estimates compared to other approaches that assume a significant volume of injectate will remain trapped as free phase CO<sub>2</sub>.

Table 3.2 shows the individual values for thickness and porosity parameters assumed for each of the major Chinese sedimentary basins evaluated, as well as the final estimated CO<sub>2</sub> storage capacity in each basin. CO<sub>2</sub> storage capacity in onshore deep sedimentary basins in China is estimated at 2,289 billion tonnes of CO<sub>2</sub> (GtCO<sub>2</sub>); offshore capacity is estimated at 779 GtCO<sub>2</sub>. Total CO<sub>2</sub> storage capacity across all basins is estimated at as much as 3,068 GtCO<sub>2</sub>. This compares favorably to capacities calculated for the U.S. (2,700 GtCO<sub>2</sub> onshore, Dahowski et al. 2005) and the E.U. (1,500 GtCO<sub>2</sub> onshore, IEAGHG 2005), and because DSFs are widely expected to become the workhorse of commercial-scale CCS deployment in most regions of the world, these preliminary capacity estimates indicate that China has strong potential for large-scale CCS deployment, depending on proximity between large CO<sub>2</sub>-emitting sources and potential CO<sub>2</sub> storage locations.

**Table 3.2.** Onshore and Offshore Basins with Assumed Thickness and Porosity Values, and Estimated CO<sub>2</sub> Storage Capacities

<b>Major Deep Sedimentary Basins</b>		<b>Average Net Sand Thickness (meters)</b>	<b>Average Porosity (%)</b>	<b>Estimated Capacity (MtCO<sub>2</sub>)</b>
<b>Onshore Basins</b>	Tarim Basin	300	15%	745,800
	Ordos Basin	300	15%	256,500
	Songliao Basin	200	15%	227,800
	Bohai Bay Basin (North of China)	200	20%	208,100
	Junggar Basin	300	15%	197,100
	HeHuai Basin (Henan, Huaibei & Huainan Basins)	300	20%	178,000
	Subei (Northern Jiangsu) Basin	300	20%	89,900
	Erlian Basin	200	15%	85,000
	Sichuan Basin	300	5%	77,600
	Turpan-Hami Basin	300	15%	54,300
	JiangHan-Dongting basin	150	20%	52,800
	Sanjiang Basin	200	15%	44,900
	Bohai Bay Basin (Liaoning)	200	20%	25,300
	Qaidam Basin	50	15%	21,500
	Hailaer Basin	100	15%	16,100
	Nanxiang Basin	100	15%	7,500
<b>Total Onshore Capacity</b>				<b>2,288,200</b>
<b>Offshore Basins</b>	East China Sea Basin	300	15%	341,800
	Southern Yellow Sea Basin	300	15%	133,800
	Bohai Wan Basin	300	20%	109,200
	Pearl River Mouth Basin	200	15%	69,700
	Yinggehai Basin	300	15%	56,000
	Northern Yellow Sea Basin	300	20%	31,500
	Beibu Gulf Basin	300	15%	23,800
	Western Taiwan Basin	100	10%	11,000
	Luzhoudao Basin	100	15%	1,900
<b>Total Offshore Capacity</b>				<b>778,700</b>
<b>TOTAL CAPACITY - DEEP SEDIMENTARY BASINS</b>				<b>3,066,900</b>

### 3.2 Depleted Gas Basins

The production of natural gas from geologic formations can result in reduced formation pressures from hydrocarbon displacement. At the same time, the presence of gas accumulations indicates the presence of the stratigraphic or structural conditions necessary to prevent gas migration over time. These characteristics combine to create a unique opportunity for CO<sub>2</sub> storage, since they demonstrate both available capacity and storage system integrity. Historic gas production data and estimates of remaining reserves provide a sound basis to estimate the ultimate CO<sub>2</sub> storage capacity for depleted gas fields. However, one additional consideration for CO<sub>2</sub> storage into gas basins is that it may not be desirable to inject CO<sub>2</sub> into the gas fields until production has been exhausted, or nearly so – except in certain

instances to boost formation pressures. Historic natural gas production has been somewhat limited to date in China and therefore many of the candidate gas basins may not be suitable for CO<sub>2</sub> storage until the basin's fields are nearing the end of their productive lives.

Data on major Chinese gas basins were compiled using the Second Atlas of Oil and Gas Basins in China (Li and Lu 2002), and in some locations data were obtained from the China Geological Survey's Sustainable Development Group (CGS 2008). In order to provide greater resolution on the location and extent of the candidate storage zones within the larger basins, locations of the gas fields were used to develop sub-basin coverages. These, particularly for some of the very large basins with select gas-producing areas, are helpful in providing more specific inputs to the spatial and economic analyses to follow. Figure 3.2 shows the spatial extent of the 17 gas basins and resulting sub-basins evaluated in this study.



**Figure 3.2.** Map Showing Major Onshore and Offshore Gas Basins in China, as Evaluated in This Study

The theoretical CO<sub>2</sub> storage capacity methodology employed for the gas basins assumes that the entire volume evacuated due to gas production can be refilled with CO<sub>2</sub>. This theoretical mass of CO<sub>2</sub> that could be stored within each gas basin at depletion is expressed by the following equation (from Liu et al. 2006b):

$$MCO_2 = 0.75 \times R_{OGIP} \times R_{CO_2/CH_4} \times \rho_{CO_2}$$

where:

$MCO_2$  is the total mass of  $CO_2$  that can be stored in the basin

$\rho_{CO_2}$  is  $CO_2$  density at standard conditions ( $1.98\text{kg/m}^3$ )

0.75 is an effective storage capacity coefficient used to represent inefficiencies of replacement-based storage in the field

$R_{OGIP}$  represents the volume of the natural gas resource remaining. These natural gas resource values reflect only technically recoverable gas, and do not take economic recoverability into consideration (Luo et al. 2001, Shangming et al. 2002). In order to facilitate comparison with capacity estimates from other parts of the world, the authors applied the natural gas resource data and calculation method presented by Zhang (2002).

And,

$$R_{OGIP} = OGIP \times R_s$$

where:

$OGIP$  is the original volume of the gas resource in place

$R_s$  is the recovery coefficient applied to estimate the recoverable fraction of OGIP, as shown in Table 3.3.

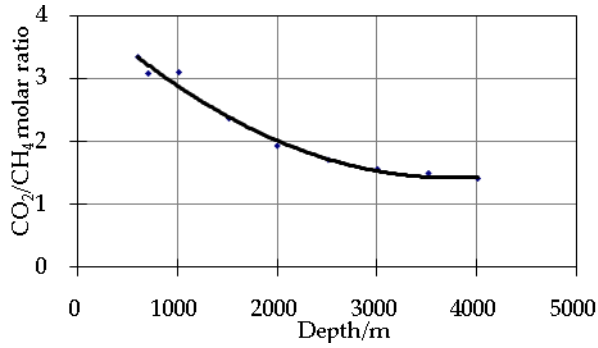
**Table 3.3.** Recovery Coefficients Applied to China Gas Basins

<b>Sedimentary Basins</b>	<b>Recovery Coefficient</b>
North of Chian, Huabei, Nanxiang, Jiangnan & Subei Basins	0.42
Ordos, Sichuan & Chuxiong Basins	0.63
Basins in Xinjiang, Qinhai & Gansu Provinces	0.55
Sanshui Basin	0.66
All Offshore Basins	0.60

And where  $R_{CO_2/CH_4}$  represents the molar replacement ratio of  $CO_2$  for  $CH_4$  at in situ pressure and temperature conditions as shown in Figure 3.3:

$$R_{CO_2/CH_4} = 2 \times 10^{-7} z^2 - 0.0015z + 4.1707$$

where  $z$  is the depth of the gas field (Koide and Yamazaki 2001).



**Figure 3.3.** Molar Ratio of CO<sub>2</sub> to CH<sub>4</sub>, by Depth (from Rogner 1997)

Table 3.4 shows the resulting capacity estimates for the 13 major onshore and 4 major offshore gas basins assessed in this study, which combine to offer a total of more than 5,100 MtCO<sub>2</sub> in total estimated CO<sub>2</sub> storage capacity. The theoretical CO<sub>2</sub> storage capacity of onshore gas basins is estimated at 4,280 MtCO<sub>2</sub>.

**Table 3.4.** Onshore and Offshore Gas Basins in China, with Estimated CO<sub>2</sub> Storage Capacities, by Major Basin

<b>Major Gas Basins</b>		<b>Estimated Capacity (MtCO<sub>2</sub>)</b>
Onshore	Ordos Basin	1,110
	Sichuan Basin	1,050
	Tarim Basin	620
	Songliao Basin	590
	Qaidam Basin	350
	Bohai Bay Basin	200
	Jiuxi-Jiudong-Huahai-Minye Basin	120
	Junggar Basin	100
	Liaohe Basin	80
	Turpan-Hami Basin	36
	Yanqi Basin	15
	Subei Basin	8
	Yilanyitong Basin	5
	<b>Total Onshore Capacity</b>	<b>4,280</b>
Offshore	Yinggehai-Southeastern Hainan Basin	680
	East China Sea Basin	160
	Bohai Bay Basin	46
	Pearl River Mouth Basin	12
<b>Total Offshore Capacity</b>	<b>900</b>	
<b>TOTAL CHINA CAPACITY - GAS BASINS</b>		<b>5,180</b>

### 3.3 Depleted Oil Basins and Enhanced Oil Recovery

As with natural gas production, the recovery of oil from geologic traps results in an overall decrease in formation pressure, and an evacuation of pore space in the host rock. Again, because historic hydrocarbon production and reserves are tracked by government and private interests, it is possible to more accurately estimate the amount of available CO<sub>2</sub> storage capacity freed up by these production activities than is possible for non-hydrocarbon-bearing reservoirs. Like natural gas pools, oil reservoirs have also proven their trapping mechanisms as suitable for retaining fluids for long periods of time. However, certain oil-bearing formations also have the added benefit of being able to produce additional oil when CO<sub>2</sub> is injected into the pore space. CO<sub>2</sub>-flood enhanced oil recovery is an important tertiary recovery option being evaluated in more and more locations and by more production companies as historic primary production volumes decline (Moritis 2009, Koottungal 2008). Coupling CO<sub>2</sub> flooding processes with long-term CO<sub>2</sub> storage may provide an opportunity to offset some of the cost associated with CO<sub>2</sub> storage for climate change mitigation purposes.

The approach used to estimate CO<sub>2</sub> storage capacity in China's oil fields was taken from Dahowski et al. (2005), and modified to accommodate available data. Data for the oil basins, including original oil in place (OOIP), were obtained from the Second and Third National Oil and Gas Resource Assessments (Li and Lu 2002), with supplemental location data taken from the China Geologic Survey's sustainable development website (CGS 2008). Using these data, the amount of oil that could be produced via CO<sub>2</sub>-flood EOR was estimated using the following method, as presented by IEA GHG (2000):

$$OOIP_c = OOIP \cdot C$$

where  $C$  represents the fraction of the OOIP able to be contacted by the CO<sub>2</sub> within the formation. This value is assumed to be 75 percent.

The proportion of additional recovery to OOIP was then calculated based on API gravity as:

$$\%EXTRA = \%EXTRA_{min} \text{ at API} < 31$$

$$\%EXTRA = (1.3 \cdot \text{API} - b) \text{ at API between } 31 \text{ and } 41$$

$$\%EXTRA = \%EXTRA_{max} \text{ at API} > 41$$

Where  $\%EXTRA$  represents the additional oil recovery due to CO<sub>2</sub> injection and  $\%EXTRA_{min}$  and  $\%EXTRA_{max}$  represent the low and high values based on commercial CO<sub>2</sub>-EOR experience to date expressed based on the API gravity of the oil.

API gravity was calculated as:

$$API = (141.5 / S_g) - 131.5$$

where  $S_g$  is specific gravity.

In the IEA GHG Early Opportunities study (IEA GHG 2002b), probabilistic simulations were used to calculate EOR potential, and thus ranges were employed for the  $\%EXTRA_{min}$  and  $\%EXTRA_{max}$  of 0.3 to 10.3 and 13.3 to 23.3, respectively. Here, median values for both variables were assumed such that



$\%EXTRA_{min} = 5.3$  and  $\%EXTRA_{max} = 18.3$ . Similarly, rather than varying coefficient  $b$  between 30 and 40, the constant median value of 35 was applied here. Once the  $\%EXTRA$  values were calculated, EOR was derived according to the function:

$$EOR = \%EXTRA \cdot OOIP_c$$

Using the relationship between API gravity and depth presented in IEA GHG (2002b), shown in Table 3.5 and designed to represent the conditions often correlated to EOR recovery factors, the fraction of low- and high-CO<sub>2</sub> oil within each basin is estimated, such that the total estimated CO<sub>2</sub> required to produce the estimated available EOR is given by the following:

$$CO_2 = ((\%low-CO_2 \text{ oil} / 100) \cdot EOR \cdot R_{L-CO_2}) + ((\%high-CO_2 \text{ oil} / 100) \cdot EOR \cdot R_{H-CO_2})$$

where  $R_{L-CO_2}$  and  $R_{H-CO_2}$  represent the typical ratios of net CO<sub>2</sub> injection to oil recovery and are taken to be 0.336 and 0.560 tonnes of CO<sub>2</sub> per barrel of oil (2.113 and 3.552 tonnes per cubic meter of oil), respectively. These ratios are based on observed results from actual CO<sub>2</sub>-EOR projects, and these median values presented in the IEA GHG (2002b) were used for this analysis.

**Table 3.5.** Four EOR Cases with Different Depth/Pressure and API Gravity Conditions (IEA GHG 2002b)

Depth	API Gravity	% low-CO <sub>2</sub> oil	% high-CO <sub>2</sub> oil
Shallow (< 2000m)	High (> 35)	100	0
Shallow (< 2000m)	Low (≤ 35)	66	33
Deep (≥ 2000m)	High (> 35)	33	66
Deep (≥ 2000m)	Low (≤ 35)	0	100

Capacity estimates were calculated at the basin level utilizing field level data where available. As with the gas basins, data on oil field locations were used to aggregate producing fields to sub-basin levels where possible, in order to provide higher resolution results in following source-reservoir matching and cost analyses. Where sub-basin groupings were developed, the basin total capacities were apportioned to the resulting sub-basins according to field-level resource size classifications as designated by the Chinese Department of Cadastral Management of the Ministry of Land and Resources (2000). Figure 3.4 shows the location of the oil basins and sub-basins examined here as having potential for storing CO<sub>2</sub>.



**Figure 3.4.** Map Showing Major Oil Basins and Sub-Basins Evaluated in This Analysis

To facilitate source-reservoir pairing and the associated costing methodology, basins or sub-basins with calculated capacities less than 2 MtCO<sub>2</sub> were eliminated from the dataset. This threshold value for reservoir capacities is driven by the combination of the 20-year commitment requirement and the minimum annual emissions cutoff for sources of 100 ktCO<sub>2</sub>/yr.<sup>1</sup> Thus, 2 MtCO<sub>2</sub> is the minimum capacity required for a formation that could be used to store the emissions from the smallest CO<sub>2</sub> source included in this analysis for the 20-year time commitment required by the base assumptions employed in this analysis. In all, there were 3 onshore oil basins that were evaluated but excluded from the analysis because they did not meet this minimum capacity threshold.

Final capacity estimates and potential additional oil production for each EOR basin are presented in Table 3.6. In total, the final 16 onshore and 3 offshore basins evaluated here with individual capacities greater than 2 MtCO<sub>2</sub> have a total estimated CO<sub>2</sub> storage capacity of 4,800 MtCO<sub>2</sub> – of which 4,600 MtCO<sub>2</sub> is found onshore. If CO<sub>2</sub>-EOR proves as successful in these Chinese oil basins as modeled, the injection of CO<sub>2</sub> could result in as much as 6,700 million barrels of incremental oil recovery onshore, and 280 MBO offshore.

<sup>1</sup> The 20-year commitment and annual emissions threshold are discussed in greater detail in Section 4.1, where the methodology and key assumptions for the geospatial and economic modeling are presented.

**Table 3.6.** Onshore and Offshore Oil Basins in China, with Estimated CO<sub>2</sub> Storage Capacity and Potential Additional Oil Production via CO<sub>2</sub>-EOR

Major Oil Basins	Estimated Additional Oil Recovery (MBO)	Estimated Capacity (MtCO <sub>2</sub> )
Songliao Basin	2,510	1,570
Bohai Bay Basin	1,860	1,490
Liaohe Depression	540	440
Ordos Basin	700	360
Junggar Basin	340	200
Turpan-Hami Basin	160	120
Subei Basin	130	100
Onshore Qaidam Basin	130	81
Tarim Basin	89	69
Nanxiang Basin	120	65
Erlian Basin	51	31
Jiangnan Basin	30	24
Sichuan Basin	32	20
Jiuxi-Jiudong-Huahai Basin	25	15
Yilanyitong Basin	17	14
Yanqi Basin	8	7
<b>Total Onshore Capacity</b>	<b>6,740</b>	<b>4,610</b>
Offshore Bohai Bay Basin	160	130
Pearl River Mouth Basin	89	41
Beibu Gulf Basin	34	18
<b>Total Offshore Capacity</b>	<b>280</b>	<b>190</b>
<b>TOTAL CHINA CAPACITY - OIL BASINS</b>	<b>7,020</b>	<b>4,800</b>

### 3.4 Unmineable Coal Seams and Enhanced Coalbed Methane Recovery

The storage mechanisms utilized for this class of geologic formations are fundamentally different from those employed in deep saline, gas- and oil-bearing formations. Rather than hydrodynamic and dissolution trapping processes, coals store CO<sub>2</sub> by chemically incorporating it via adsorption onto the cleat structures of the coal. Often, these structures already contain methane, but because CO<sub>2</sub> results in a more stable chemical bond, injecting CO<sub>2</sub> into the coals allows the methane to be released from the coal itself which can then be produced to the surface for recovery, cleanup, and sale. During the process, CO<sub>2</sub> is preferentially adsorbed onto the coal surfaces, resulting in isolation of the CO<sub>2</sub> from the atmosphere. This process, known as CO<sub>2</sub>-driven enhanced coalbed methane recovery (CO<sub>2</sub>-ECBM), while not yet a commercial technology, is being investigated to address technical issues and move the process closer to commercial deployment (Metz et al. 2005). The authors have chosen to include capacity estimates for ECBM and to include it in the cost curve analysis to provide a basis for understanding the potential role that ECBM-based storage may play in China should the technology become mature and economic enough for wide-scale use.

Spatial data on China’s major coal-bearing regions were obtained from the United States Geological Survey (2000) and supplemented by additional and higher-resolution data where available. Figure 3.5 shows the coal basins in China that were analyzed in this study.



**Figure 3.5.** Map Showing the Location and Extent of Major China Coal Basins Analyzed in This Study

Key characteristics of the coal resource within each basin were compiled to estimate CO<sub>2</sub> storage capacity and potential for recovery of coalbed methane via CO<sub>2</sub>-ECBM based on the method outlined below.

Coalbed methane reserves were estimated as a fraction of total coal reserves in each basin known to have coalbed methane potential (based on Liu et al. 2005). Because few data exist on the areal extent of CBM fields in China, and a definitive understanding of what will constitute unmineable coal has not been determined, the following relationship has been applied in order to estimate CO<sub>2</sub> storage capacity for this potential storage option without complete information (from Hendriks et al. 2004):

$$SCO_2 = a \times \rho_{CO_2} \times \sum_{i=1}^n \sum_{j=1}^{10} (G_i \cdot C_{ij} / C_i \times RF_{ij} \times ER_{ij})$$

where:

$a$  is the fraction of a coal basin that contains recoverable coalbed methane. This value was assumed to be 10%

$G_i$  is the coalbed methane resource in reservoir  $i$

$C_{ij}$  is the coalbed methane resource in coal type  $j$  within reservoir  $i$

$C_i$  is the total coalbed methane resource of reservoir  $i$

$RF_{ij}$  is the assumed coalbed methane recovery rate of coal type  $j$  within reservoir  $i$

$ER$  is the volumetric replacement ratio of  $CO_2$  to  $CH_4$  of coal type  $j$  within reservoir  $i$

$\rho_{CO_2}$  is the density of  $CO_2$

This method assumes that the entirety of the recoverable coalbed methane resource (located within 10% of each coal basin) is suitable for  $CO_2$  storage via displacement of methane. Replacement ratio and recovery rate were estimated for each coal type found in China, as shown in Table 3.7 below.

**Table 3.7.** Assumed Replacement Ratios and Recovery Rates for the Ten Coal Type Categories Identified for Chinese Coal Basins (From Liu et al. 2005, based on Reeves 2002, Bustin 2002)

Coal Class	Replacement Ratio ( $CO_2:CH_4$ )	Recovery Rate
Lignite	10	1.00
Non-caking coal	10	0.67
Weakly caking coal	10	1.00
Long flame coal	6	1.00
Gas coal	3	0.61
Fat coal	1.5	0.55
Coking coal	1	0.50
Lean coal	1	0.50
Meager coal	1	0.50
Anthracite	1	0.50

Total capacity in deep, unmineable coal seams via ECBM in China is estimated at approximately 12,000 Mt $CO_2$  within 45 major coal basins. These basins could potentially yield as much as 16 Tm<sup>3</sup> (565 Tcf) in recovered coalbed methane resource if and when ECBM proves to be a viable commercial scale process and the assumptions made here bear out in practice. Table 3.8 lists the 45 coal basins analyzed, along with the estimated  $CO_2$  storage capacity and total potential coalbed methane reserves of each basin. Note that again, a minimum threshold capacity of 2 Mt $CO_2$  was required in order for basins to be included for further analysis.

**Table 3.8.** Estimated CBM-Based Storage Capacities for 45 Major Coal-Bearing Basins in China, and Associated CBM Reserves

<b>Coal Bearing Region</b>	<b>Total CBM Potential (Million m<sup>3</sup>)</b>	<b>Estimated Capacity (MtCO<sub>2</sub>)</b>
Ordos Basin & Hedong-Weibei	4,820,400	4,450
Turpan-Hami Basin	1,868,200	2,200
Santang Lake	838,200	990
Eastern Junggar	551,300	650
Qinshui Basin	3,100,100	610
Ili Basin	496,700	560
Northern Junggar	518,200	530
Southern Junggar	436,600	340
Sanjiang & Muling River	218,700	240
Datong-Ningwu	282,000	160
Huainan	271,000	120
Yanqi Basin	201,000	120
Liupanshui	521,500	110
Eastern Tarim	169,800	100
Southern Sichuan-Northern Guizhou	398,400	79
Xuzhou-Huaipei	173,600	78
Zhangjiakou	64,600	72
Northern Yellow River	145,700	68
Western Henan	190,200	56
Tangshan	124,100	55
Eastern Piedmont of Taihang Mountains	189,100	51
Xuanhua-Yuxian	31,300	44
Helan Mountains	146,900	38
Northern Tarim	62,600	36
Northern Qaidam	22,200	30
Daqin-Wula Mountains	14,400	27
Qilian	37,400	25
Beijing	42,700	25
Jingyuan-Jingtai	36,400	14
Dunhua-Fushun	5,900	11
Eastern Sichuan	51,200	11
North Qilian Corridor	10,100	11
Kuming-Kaiyuan	5,500	10
Beipiao	7,600	8
Tiefu-Fuxin	6,600	7
Yilan-Yitong	3,200	6
Baise	3,300	5
Yanbian	2,800	5
Pingxiang-Leping	19,700	4
Lianyuan-Shaoyang	16,800	4
Nanning	2,100	3
Chenzhou-Zixing	14,400	3
Panzhuhua (Dukou)-Chuxiong	6,700	2
Yongan-Xingning	12,200	2
Suzhou Zhejiang Anhui Province region	5,200	2
<b>TOTAL CHINA CAPACITY - COAL BASINS</b>	<b>16,146,600</b>	<b>11,970</b>

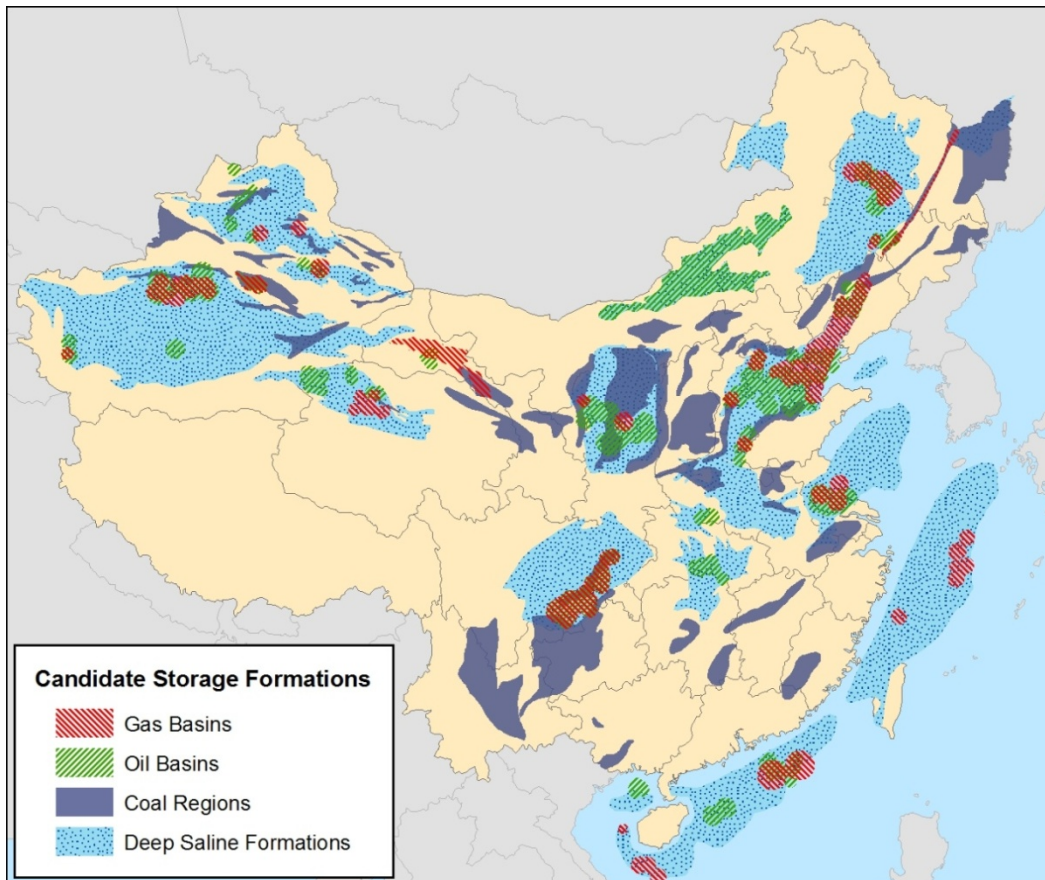
### 3.5 Summary of Candidate Storage Reservoirs

Table 3.9 shows the total estimated storage capacities in each formation type (for both onshore and offshore basins), as well as the total capacity over all formation types in China. Overall, there is estimated to be the potential for over 2,300,000 MtCO<sub>2</sub> of storage capacity in onshore basins in China, and some 780,000 MtCO<sub>2</sub> in relatively near offshore basins. Deep saline-filled sedimentary basins account for over 99% of the total calculated storage capacity, echoing findings in other parts of the world regarding the central importance of this class of reservoirs for large-scale CCS deployment. This represents a significant resource, at a similar scale as found in other major industrialized areas such as North America (Dahowski et al. 2005) the European Union (Wildenborg et al. 2005), Australia (Bradshaw et al. 2004) and elsewhere, and is likely to serve China well should broad, large-scale deployment of CCS be desired as a method of addressing greenhouse gas emissions within China.

While small relative to the extremely large theoretical CO<sub>2</sub> storage resource found in deep saline-bearing sedimentary formations, China also appears to possess a significant storage resource in value-added storage formations—those formations that might provide offsetting revenue via the co-production of hydrocarbon commodities. Though small and likely of limited duration relative to DSF-based storage, China’s value-added capacity represents a potential suite of opportunities for early demonstration of CCS that may also yield economic benefits as incentives to Chinese and international partners hoping to develop pilot projects. Figure 3.6 is a map showing all of the candidate CO<sub>2</sub> storage reservoirs in China identified and analyzed in this report.

**Table 3.9.** Total Capacities and Resulting Number of Formations within the Four Major Storage Formation Classes Analyzed

<b>Formation Type</b>	<b>Number of Candidate Storage Formations</b>	<b>Estimated CO<sub>2</sub> Storage Capacity (MtCO<sub>2</sub>)</b>
<b>Deep Saline Sedimentary Basins</b>	<b>25</b>	<b>3,066,900</b>
<i>Onshore</i>	16	2,288,200
<i>Offshore</i>	9	778,700
<b>Depleted Gas Basins</b>	<b>17</b>	<b>5,180</b>
<i>Onshore Gas Fields</i>	13	4,280
<i>Offshore Gas Fields</i>	4	900
<b>Depleted Oil and EOR Basins</b>	<b>19</b>	<b>4,800</b>
<i>Onshore Oil Basins</i>	16	4,610
<i>Offshore Oil Basins</i>	3	190
<b>Coal Basins</b>	<b>45</b>	<b>11,970</b>
<b>TOTAL CHINA CAPACITY</b>	<b>106</b>	<b>3,088,850</b>



**Figure 3.6.** Map Showing the Combined Location and Extent of Candidate Geologic CO<sub>2</sub> Storage Formations Analyzed in This Study



## 4.0 Cost Curve Methodology

This chapter presents the core methodology and assumptions applied to the development of the cost curves for CO<sub>2</sub> transport and storage for China. Most of the methodology is based on the existing capabilities of the *Battelle CO<sub>2</sub>-GIS* geospatial techno-economic modeling tool and follows the procedures applied and outlined by Dahowski et al. (2005). A review of the methodology follows, with special emphasis on updates to data and assumptions that have been made to reflect both more recent cost estimates as well as factors that are specific to the expected costs of deploying CCS in China.

It is important to note that development of this methodology and the resulting cost analyses often required the application of assumptions for key parameters impacting final costs of CO<sub>2</sub> transport and storage in China. As a guiding principal, the authors approached these assumptions as realistically as possible, yet tending to err on the side of overestimating, rather than underestimating, resulting costs. The estimates presented here are thus considered “conservative” as discussed in the following sections.

### 4.1 Modeling Approach

The primary focus of this study – the development of cost curves for commercial-scale CCS in China – is accomplished via the application of the *Battelle CO<sub>2</sub>-GIS* economic modeling tool. The basic approach centers on the pairing of the set of CO<sub>2</sub> sources and candidate storage reservoirs within a system, subject to a set of constraints:

***Source-Reservoir Pairing*** – First, utilizing geospatial and technoeconomic capabilities within the *CO<sub>2</sub>-GIS* model, the entire set of possible source-sink combinations is determined within a specified maximum search radius. Levelized costs for CO<sub>2</sub> transport and storage (including site characterization, measurement, monitoring and verification and other aspects of a complete storage system as detailed below) are calculated for each pair, based on the distance between, and characteristics of, the source and selected reservoir.

***Competition and Societal Cost Minimization*** – Because there may be many sources seeking to store their CO<sub>2</sub> into a select candidate storage reservoir, a least-cost optimization process is run to determine which source(s) may be allowed access. The cost optimization seeks to minimize overall societal costs by seeking the CO<sub>2</sub> storage projects with the lowest overall per-ton costs. The selection process is further constrained by the estimated CO<sub>2</sub> storage capacity of each reservoir, limiting the volume of CO<sub>2</sub> – and hence the number of CO<sub>2</sub> sources – that can be accepted. As a result, each source is paired with its lowest-cost acceptable storage reservoir, which may be, but is often not, the source’s first choice. In some cases, a source will not be able to locate a storage reservoir capable of accepting its CO<sub>2</sub> within the search radius, and the source in this case – along with its CO<sub>2</sub> – will be considered to be stranded.

***Reservoir Filling Constraints*** – Each reservoir is allowed to be matched with the set of lowest-cost sources that have selected it up until the point at which the reservoir capacity has been fully allocated. In order to ensure that project investment time horizons are realistic, and to prevent a given reservoir’s capacity from being completely exhausted within only a few years (and requiring sources to build new

transport and injection infrastructure after such a short time period), an additional constraint is imposed within the optimization such that a reservoir must have enough available capacity to store a paired source's CO<sub>2</sub> for a minimum of 20 years.<sup>1</sup>

**Base Project Economic Assumptions** – For the purposes of this analysis, project lifetimes were assumed to be 20 years. All costs are expressed in 2005 US dollars. An annual discount rate of ten percent was assumed, resulting in an annual capital charge rate of 11 percent. Where costs in other base years were used, these costs were inflated or deflated to 2005 dollars using the U.S. consumer price index adjustment (USBLS 2009).

Further, in an attempt to modify these costs (most of which are based on U.S. assumptions) to values likely to be borne by projects deployed in China, a relative scaling factor was applied. Scaling factors of 90% for capital costs and 80% for the more labor-intensive O&M costs were assumed, based on factors assigned within the IEA Energy Technology Perspectives model (Gielen 2003). Gielen presents cost multipliers for 15 regions of the world, including China, relative to the United States. These multipliers – 90% of U.S. costs for investment and 80% for both fixed and variable O&M – are reported to be forward looking and valid out to 2050, and higher than historical values. These scaling factors are applied on top of each of the respective resulting capital and O&M costs, which are documented in the following sections.

## 4.2 CO<sub>2</sub> Source Assumptions

There are a number of important assumptions regarding the development and application of the CO<sub>2</sub> point source data that have a significant impact on the calculation and interpretation of the CO<sub>2</sub> transport and storage cost curves for China. These include the following:

**Capture Cost** – The cost of capturing CO<sub>2</sub> from the flue gas or process stream of each identified source is outside the scope of this particular study. Capture costs are therefore not included in the overall costs estimated for each source-reservoir pair. Future analyses will be able to integrate costs of CO<sub>2</sub> capture into the overall CCS project cost estimates to provide a more complete assessment of likely end-to-end CCS system costs.

**Compression and Dehydration Costs** – The costs associated with dehydrating and compressing captured CO<sub>2</sub> to prepare it for pipeline transport are likewise outside the scope of this current study. These costs are therefore purposefully neglected in this analysis and each CO<sub>2</sub> point source is assumed to deliver a uniform, compressed, pipeline-ready supercritical CO<sub>2</sub> stream to a pipeline at the plant gate. This is an important modeling assumption as it indicates that the operators of potential CO<sub>2</sub> storage reservoirs will be indifferent as to the type of source (and specific source) supplying the CO<sub>2</sub> for storage.

**Minimum Emissions Cutoff** – The present study, like others before it (see Dahowski et al. 2005, Wildenborg et al. 2005, IEA GHG 2002b), does not consider CO<sub>2</sub> point sources that emit less than

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<sup>1</sup> In the North American Cost Curve Study (Dahowski et al. 2005) a 10-year filling constraint was imposed in the Reference Case and a 20-year case was examined in a sensitivity analysis. As a result of that and subsequent analyses, a 20-year constraint was selected for this study to better represent the longer-range investment and infrastructure requirements likely to be associated with CCS projects.

100,000 tonnes of CO<sub>2</sub> per year. This assumption is rooted in the common belief that given the capital-intensive nature of CCS and economies of scale working against them, very small CO<sub>2</sub> point sources will be far less likely to invest in CO<sub>2</sub> capture and storage systems compared to much larger sources.

***Retired or Planned Sources*** – This analysis ignores CO<sub>2</sub> point sources that have been identified as either no longer or not yet operational. With industries growing as fast as they are in China, it is challenging to maintain an up-to-date catalog of plants and accurately track the status of planned or retired facilities. This challenge is compounded by data availability issues; yet, the intent has been to focus on sources that were operating at the time of data collection. Due to the geography-dependent nature of the source-sink pairing methodology, the current study is unable to examine projected growth rates for specific industries and estimate the impacts on the demand for and costs of CCS. The methodology may be modified to include such estimates in the future.

***Capture Efficiency*** – A constant capture efficiency of 90% has been applied equally to all CO<sub>2</sub> sources. This assumption is consistent with Metz et al. (2005) and based on the idea that while it might be technically possible to capture nearly all of the CO<sub>2</sub> in a given process stream that in reality it will typically be economic to capture 90% of the CO<sub>2</sub> with 10% vented to the atmosphere (for those streams that are amenable to CO<sub>2</sub> capture). As a result, the mass flow rate of CO<sub>2</sub> that is transported and injected into a storage reservoir represents 90% of the total annual emissions for each source.

### **4.3 CO<sub>2</sub> Transport Costs**

Though offshore CO<sub>2</sub> storage opportunities may be important for the highly industrialized coastal regions of China that may be otherwise limited in nearby onshore storage options, the focus of the present analysis is on CO<sub>2</sub> storage in onshore basins. Broadening the evaluation to consider the potential and costs for storage in offshore formations will provide a useful follow-on analysis; yet, this initial assessment of onshore CCS opportunities will nevertheless provide significant value in identifying CO<sub>2</sub> sources that have higher-than-average storage costs, or that are stranded by their lack of proximal onshore storage reservoirs. The capacities presented in Chapter 3 include preliminary estimates for offshore basins to support future sensitivity analyses that allow these basins to compete against onshore storage options in order to examine the tradeoffs between higher per-distance transport and additional costs associated with offshore storage, and the lack of lower-cost opportunities onshore.

Therefore, land-based pipelines are assumed to provide all CO<sub>2</sub> transport needs in this analysis. They are the preferred method for transporting the quantities of CO<sub>2</sub> being examined here, from CO<sub>2</sub> point sources to onshore candidate CO<sub>2</sub> storage formations. A further modeling assumption is that each source will have its own dedicated pipeline to transport its CO<sub>2</sub> to selected storage reservoir. In reality, some coordination would likely be sought where appropriate and where timing and proximity might incentivize joint investment. However, Wildenborg et al. (2005) demonstrated in an analysis centered on the European Union that there was no significant cost savings resulting from highly networked pipelines, and the authors feel that dedicated source-reservoir pipelines provide a reasonable and conservative basis for examining transport costs in this type of analysis.

The cost estimates and modeling assumptions for onshore CO<sub>2</sub> pipelines used in this study are as follows:

**Pipeline Costs** – Capital costs associated with pipeline infrastructure development were calculated using the following relationship derived using multivariate regression analysis of 10 years of recent U.S. onshore natural gas pipeline costs reported to the Federal Energy Regulatory Commission (Smith 2006).<sup>2</sup> All costs were adjusted to 2005 dollars, with high and low cost outliers for each size category excluded. Finally, empirical data on CO<sub>2</sub> pipeline flow rate and diameter from operating CO<sub>2</sub> pipelines in the U.S. was applied to develop the following pipeline cost algorithm:

$$\text{Pipeline cost (\$)} = d \cdot 398,519 \cdot Q^{(0.4055)} + 466,464$$

Where  $d$  is the pipeline length (in miles) and  $Q$  is the average annual CO<sub>2</sub> mass throughput (in MtCO<sub>2</sub>/y).

For the purposes of this study, annual O&M costs are assumed to be 2.5% of capital, as suggested by McCollum and Ogden (2006) based on their review of a number of CO<sub>2</sub> transport studies, and similar to what has been applied in previous work (Dahowski et al. 2005).

**Pipeline Assumptions** – The base transport distance required for each source-reservoir pair is determined by the CO<sub>2</sub>-GIS as the distance between them. To that straight-line distance, a 17% routing factor is added plus an additional 25 miles to allow for additional pipeline needed to access a suitable injection site within a given storage formation.<sup>3</sup> Thus, a CO<sub>2</sub> source and storage reservoir that are co-located (distance from source to sink is zero miles) would still incur minimum transport costs associated with a 25-mile long pipeline. At this time no additional factors have been included to account for varying terrain or other cost impacts at this scale.

## 4.4 CO<sub>2</sub> Storage Costs

This section summarizes the costs modeled for the various aspects of CO<sub>2</sub> storage, including site characterization, infrastructure development, O&M, site monitoring, and costs and revenues associated with value-added CO<sub>2</sub> storage (via enhanced oil and coalbed methane recovery).

### 4.4.1 Site Characterization

Based on recent published estimates, the average cost to drill and log site characterization wells will be roughly \$3,000,000 (per well, each covering a 25-square-mile increment of project area); the cost of acquiring seismic data will be approximately \$100,000 per square mile; and the costs associated with data analysis from each of these efforts will account for an additional 30 percent of data acquisition costs (McCoy and Rubin 2009). Early versions of this work assumed a constant area of review of five square miles, requiring \$500,000 of seismic data acquisition, coupled with the \$3,000,000 characterization well and \$1,050,000 in associated data analysis costs, yielding a flat per-project cost characterization cost of \$4,550,000 (Dahowski et al. 2009). However, because the area requiring characterization will vary

<sup>2</sup> Very few data on pipeline costs in China are available and therefore for the present study the application of U.S.-based costs have been adopted and assumed to represent a reasonable estimate at this time of expected costs for pipelines in China.

<sup>3</sup> Note that this is greater than the 10-mile transport adder that has been applied previously for analyses in the U.S. (Dahowski et al. 2005). A longer 25-mile minimum pipeline distance was selected for this study due to the comparatively lower spatial accuracy for the CO<sub>2</sub> point source data and lower resolution of the candidate storage basin outlines that are available for China.

significantly from one project to the next depending not only on the ultimate stored volume of CO<sub>2</sub> but also on the individual characteristics of the formation into which its CO<sub>2</sub> is being injected (driven primarily by thickness, porosity and solubility), the approach was updated to better account for the real-world variations in area of review that would be expected from one project to the next.

While it is currently impractical to calculate the area of review for every source-sink pair evaluated within this analysis, areas were estimated as a function of the total lifetime injection volume for a given source, and the average storage density of the matched sink. For DSFs, storage density was simply calculated by dividing the total capacity by the basin's area to arrive at an average capacity per unit surface area. Because data on field areas were not available for gas fields, the storage density value applied for a given DSF was also applied to gas fields within the same basin. For coals, based on the assumption (see Section 3.4) that ten percent of each coal basin's area is suitable for coalbed methane recovery, the area of each basin was reduced by 90 percent when calculating storage density. For oil fields, average field areas were calculated for each oil-bearing basin based on field area data and these areas were used in calculating storage density for oil-based capacity.

Per-project characterization costs calculated using this updated method range from \$4 million to over \$700 million for the Reference Case (as described in Chapter 5), with per-ton costs ranging from \$0.35/tCO<sub>2</sub> to over \$140/tCO<sub>2</sub>, averaging about \$2/tCO<sub>2</sub>. The large variation in resulting costs is driven primarily by the range in project size and the range in geologic settings and related parameters that both impact the likely areal extent of the CO<sub>2</sub> plume. All else being equal, larger projects with higher CO<sub>2</sub> flow rates generally result in higher total project costs yet lower costs on a per ton basis, while thicker and more permeable storage zones will result in lower project and per-ton characterization requirements. These costs, while higher than those assumed by previous studies (e.g., Dahowski et al. 2005), are utilized in this analysis to better account for the recent and steeply upward trend in wellfield services costs including drilling, logging and seismic services.

#### **4.4.2 Well-Field Costs**

The costs assumed for drilling, completing, operating and maintaining CO<sub>2</sub> injection wells and oil and gas production wells (for EOR and ECBM) are described below. Note that, in all cases, vertical injection wells are assumed. Though directional wells have been used with great success by many hydrocarbon production projects as well as some early CCS projects (Knott 2008), the performance and cost effectiveness of directional wells is highly project specific and difficult to generalize at this time for an assessment at this scale. It is worth noting however, that by assuming only vertical wells this analysis might be overestimating a portion of the resulting costs in the long term if directional drilling becomes common for CCS.

**Well Capital Costs** – Per-well capital costs for injection and production wells are based on regression analysis of onshore oil and gas well drilling cost data reported by the 2003 Joint Association Survey on Drilling Costs and presented in Augustine et al. 2006.<sup>4</sup> In order to account for recent increases in drilling costs beyond standard inflation, costs were escalated based on an index derived from a summary of historical drilling cost trends as reported by the EIA Annual Energy Review (2008a).

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<sup>4</sup> See Section 4.4.5 for a discussion of modeled costs for monitoring wells.

Thus, well costs (for both production and injection wells) are estimated using the following expression:

$$\text{Well cost (\$/well)} = 1,000,000 \cdot 0.1271e^{0.0008z} + 530.7z$$

where  $z$  is the depth of the well, in meters.

**Other Injection Field Infrastructure** – Per-well field costs for flowlines and connections are estimated using the relationship presented by Bock et al. (2003), given here in 1999 dollars and converted to 2005 dollars prior to use:

$$\text{Per-well flowline \& connection cost} = 43,600 \cdot (7,389 / (280n))^{0.5}$$

where  $n$  is the number of wells in the field.

**Annual Wellfield O&M Cost** – Using annual costs presented in the same paper by Bock et al., for normal daily expenses, consumables, surface maintenance and subsurface maintenance (repair and servicing), the following relationship is used to estimate operating and maintenance costs for the project well-field:

$$\text{Annual per-well O\&M cost} = 24,600 + [13,600 \cdot (7,389 / (280n))^{0.5}] + [(5,000z) / 1219]$$

where  $n$  is the number of wells, and  $z$  is the well depth, in meters.

#### 4.4.3 Estimating Injection Rates

The number of CO<sub>2</sub> injection wells, as well as the number of oil and gas production wells for EOR and ECBM, is an important factor contributing to the overall cost of CO<sub>2</sub> storage. While only limited and aggregate data is available on the geology of basins in China that may be suitable candidates for CO<sub>2</sub> storage, available data has been augmented with assumptions as needed to estimate reasonable per-well injection rates for each different class of storage formation.

**Deep Saline Sedimentary Formations and Gas Basins** – Variations in CO<sub>2</sub> injection rates are an important economic driver of storage costs that, to date, have been largely neglected by studies of this type (e.g., Dahowski et al. 2005, Wildenborg et al. 2005) as a result of a lack of adequate data at the basin scale. However, it is clear that in general, formations with higher potential injection rates – governed primarily by permeability and injection interval thickness – will have lower associated per-ton costs than formations where per-well injection rates are not as promising, requiring the construction of relatively more injection wells to store the same volume of CO<sub>2</sub>. The European cost curve study (Wildenborg et al. 2005) applied a constant injection rate of 1,000,000 tonnes/well-y for deep saline formations based on the experience of the Sleipner project. In the development of cost curves for North America (Dahowski et al. 2005), a constant and overall conservative annual injection rate of 200,000 tonnes/well was assumed for all deep saline and gas formations; subsequent investigations indicate that expected injection rates vary considerably and are often significantly greater than this. For these reasons, the authors have chosen to incorporate a range of potential injection rates into the current analysis.

It is important to note that injection rates have not been quantitatively derived from the formation parameters shown, and do not constitute actual injection rates. Rather, they are intended to bin the formations (relative to each other) into *Low*, *Moderate*, *High* and *Very high* injection rate classes, within a reasonable range of possible injection rates, in order to resolve the relative impact of injection rate as a cost signal in the economic modeling. Because the global set of CO<sub>2</sub> storage projects to date is still too small to provide any widely applicable statistical method of quantifying the true ability of a formation to accept CO<sub>2</sub> under a wide range of conditions, it was necessary to apply several assumptions.

The experience of the Sleipner project, with an injection rate of approximately 1,000,000 tCO<sub>2</sub>/yr via a single well, was used to benchmark the rate for the *Very high* rate class. However, to account for the fact that injection rates this high are unlikely to occur consistently throughout a basin, this maximum rate was adjusted downward to 800,000 tCO<sub>2</sub>/yr per well for the *Very high* rate class. The Algerian In Salah project was used to benchmark our assumptions for the *Low* rate class, where very low permeabilities (< 10 mD) and thicknesses (average 20 m) lead to a very low vertical well injection rate of around 40,000 tCO<sub>2</sub>/yr (Riddiford et al. 2004).<sup>5</sup> While there are likely to be some formations in China with similar characteristics, because none of the basins in China show average aggregate values that are this low, this rate was adjusted upward to define the *Low* rate class as exhibiting an average per-well injection rate of approximately 100,000 tCO<sub>2</sub>/y. The *Moderate* and *High* classes were then defined by intermediate annual injection rate assumptions of 200,000 and 400,000 tCO<sub>2</sub>/well.

The rates and classes assigned to each formation are intended to yield conservative cost estimates for DSFs, while still allowing for differentiation between basins of varying economic attractiveness. Table 4.1 shows the representative permeabilities and net sand thicknesses assumed for each formation based on available data, as well as the assigned injection class categories and the assumed annual injection rates associated with each assigned rate class.

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<sup>5</sup> Vertical well injection rate assumed to be 10% of horizontal injection rate per Benson (2006).

**Table 4.1.** Key Geologic Parameters, and Assumed Injection Rate Classes and Rates for the Major China DSFs Evaluated in this Study

Onshore Basin	Representative permeability (mD)	Average Net Sand Thickness (m)	Injection Rate Class	Annual Rate (tCO <sub>2</sub> /well)
Bohai Bay Basin (Niaoning)	1100	200	Very high	800,000
Bohai Bay Basin (North of China)	1000	200	Very high	800,000
Erlian Basin	75	200	Low	100,000
Hailaer Basin	1000	100	Very high	800,000
HeHuai Basin (Henan/HuaiBei/Huainan)	150	300	High	400,000
JiangHan-Dongting basin	450	150	High	400,000
Nanxiang Basin	150	100	Moderate	200,000
Ordos Basin	50	300	Moderate	200,000
Qaidam Basin	250	50	Low	100,000
Sanjiang Basin	250	200	High	400,000
Sichuan Basin	<10	300	Low	100,000
Songliao Basin	250	200	High	400,000
Subei (Northern Jiangsu) Basin	75	300	Moderate	200,000
Tarim Basin	150	300	High	400,000
Turpan-Hami Basin	500	300	High	400,000
Western Taiwan Basin	450	100	High	400,000
Zhunggar Basin	75	300	Low	100,000

In addition to the number of wells required based on the combination of the source’s CO<sub>2</sub> flow rate and the reservoir’s allowable injection rate, the cost model also accounts for a small number of additional wells. This is to account for some variation in actual per-well injection rates as well as for backup injection capacity within the wellfield should a well need to be taken offline for a time for routine maintenance or an off-normal event. Because a majority of storage projects are likely to be injecting CO<sub>2</sub> in response to a policy action to avoid atmospheric venting of CO<sub>2</sub>, some type of extra capacity in the overall system is likely to be desired to limit the payment of a penalty or required purchase of an offset. In order to model for engineered redundancies that would allow the project to continue to meet its CO<sub>2</sub> mitigation goals, additional backup wells have also been costed into this analysis for DSF- and gas basin-based storage projects, at a rate of one backup well for every ten project wells or fraction thereof. For example, a project with 1-10 primary injection wells would require a single backup well, while a project with 11-20 primary wells would require two extra injection wells.

**Enhanced Oil Recovery** – Because enhanced oil recovery, like coalbed methane recovery, is focused on optimizing incremental hydrocarbon production rather than simply maximizing the amount of CO<sub>2</sub> that can be practically and safely injected into a geologic storage formation via a well (as is the case with DSFs), the injection rate becomes an even more important cost and operational consideration. The lower per-well injection rates required to optimally flush oil to the production wells result in higher per-ton injection costs because of the additional wells needed to achieve the same injection rate relative to a non-value-added formation like a DSF or depleted gas basin.



Some previous CCS costing studies have applied CO<sub>2</sub> injection rates based on field data from the early years of CO<sub>2</sub>-EOR projects (see Dahowski et al. 2005). However, CO<sub>2</sub> injection rates are often highest at the beginning of a CO<sub>2</sub> flood (particularly in terms of new, non-recycled CO<sub>2</sub>) and these rates are typically unsustainable over the course of the project. In order to better model the costs associated with operating a CO<sub>2</sub>-EOR project within the framework of this analysis, a revised approach was taken to account for the cost impact that would be associated with a requirement to take the same amount of CO<sub>2</sub> over the full 20-year typical life of the project. A lower per-well injection rate was sought that better represented the average injection rate of new CO<sub>2</sub> over the course of the project's life. However, only very limited data from CO<sub>2</sub>-EOR pilot projects in Chinese oil fields exists.

This was overcome by evaluating the life-cycle CO<sub>2</sub> injection and production rates for a typical CO<sub>2</sub>-EOR project in the U.S. as presented by Jarrell et al. (2002). Based on this information, and the assumption that all CO<sub>2</sub> produced back to the surface via the oil well is re-injected, an estimate of the "new CO<sub>2</sub>" injection rate over the project lifetime was developed, as shown in Figure 4.1.<sup>6</sup> Note the characteristic injection rate decline over time, not only for total CO<sub>2</sub> injection, but especially for the newly purchased CO<sub>2</sub> as the rate of recycled CO<sub>2</sub> increases. By the end of the 20 year project life shown here, recycled CO<sub>2</sub> meets 100 percent of the project's total injection requirements, and additional new deliveries of CO<sub>2</sub> are no longer needed. To translate this effect into an average annual injection rate that could be used in this study, observed injection rates from the early years of the U.S. Kelly-Snyder field, used as a case study for injection rates by Dahowski et al. (2005), were matched to this recycled-vs-new CO<sub>2</sub> injection curve. The resulting 20-year average per-well injection rate applied in this study – based on the amount of new CO<sub>2</sub> only, after accounting for recycled CO<sub>2</sub> – was estimated at 21,000 tCO<sub>2</sub>/y. While actual injection rates will vary from project to project, this value has been applied as representative of the possible injection rates for all CO<sub>2</sub>-EOR modeled in this analysis.

**Enhanced Coalbed Methane** – For storage of CO<sub>2</sub> into coal seams and development of ECBM, there have been very few projects of sufficient scale to be used to estimate potential sustainable injection rates. Small tests have been conducted in China and elsewhere, but injected volumes, duration, and overall project size preclude reliable estimation of sustainable, decade-scale injection rates. Two of the larger ECBM projects have occurred in the U.S. and these have been cited in previous studies as a basis for assumed injection rates (e.g., Dahowski et al. 2005). In this study, the authors again point to the experience from the BP Tiffany Unit and Burlington Allison Unit ECBM projects to estimate injection rates. However, based on the very low injection rates seen in more recent pilot tests around the world, the assumed per-well injection rate has been adjusted to 14,000 tCO<sub>2</sub>/y, the lower value from these two projects. This rate may be further adjusted to incorporate more current data as additional studies are performed on the injection of CO<sub>2</sub> into coals.

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<sup>6</sup> "New CO<sub>2</sub>" represents CO<sub>2</sub> that is delivered from an anthropogenic CO<sub>2</sub> point source using CCS to reduce its greenhouse gas emissions to the atmosphere, and excludes all recycled CO<sub>2</sub> that is re-injected into the field. The recycled CO<sub>2</sub> was once new CO<sub>2</sub> that has already been injected and has been produced at a production well. It is primarily the new CO<sub>2</sub> that we are concerned with in this analysis since it is what is captured at the source and transported to the injection site via pipeline and for which we must estimate injection rates, since we require an EOR project to take all of a source's CO<sub>2</sub> for a full 20-year period.

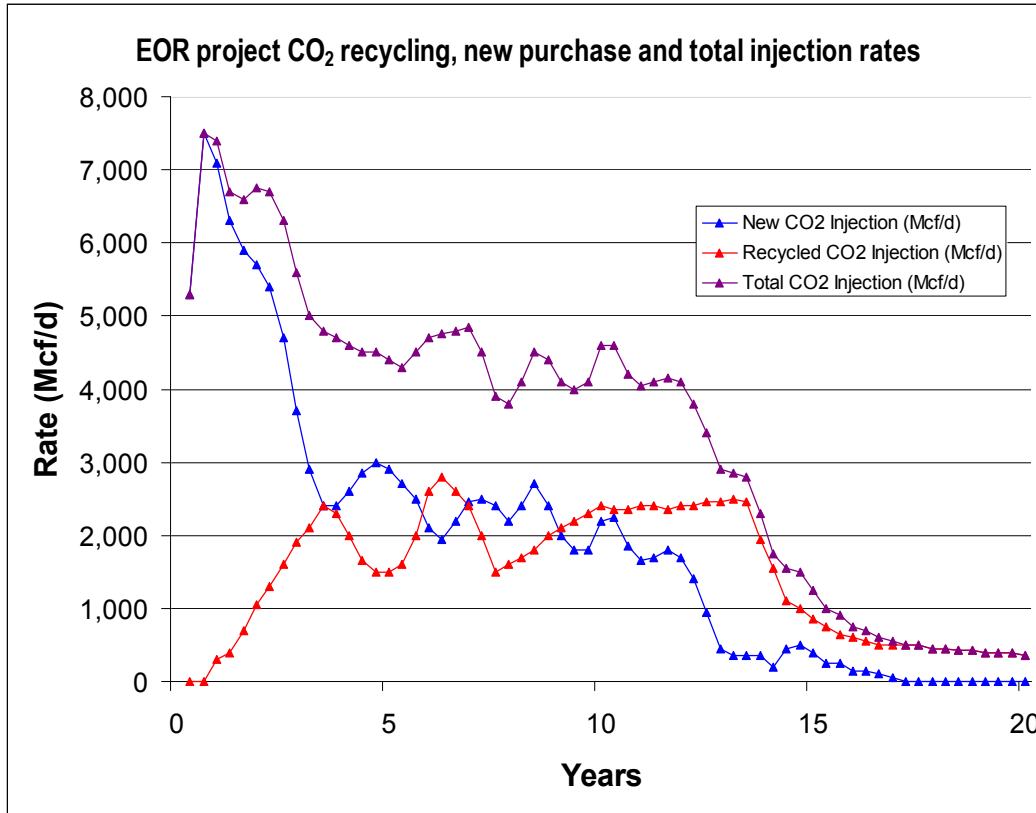


Figure 4.1. EOR Project CO<sub>2</sub> Injection Rate Over Time, and Proportion of Injectate as Recycled and New CO<sub>2</sub>, After Jarrell et al. (2002)

#### 4.4.4 EOR and ECBM Considerations

For projects involving EOR and ECBM the following additional economic assumptions are made.

**Production Wells** – In order to account for the additional costs for production infrastructure associated with EOR- and ECBM-based CCS projects, cost estimates for these value-added projects include capital and operating costs for production wells in addition to injection wells.

For EOR projects, the authors have applied an assumption that each injection well requires 1.5 oil production wells. This is based on published data from the Oil & Gas Journal’s latest EOR Survey (Kootungal 2008), which show an average ratio of injection wells to production wells of 1:1.47 for U.S. EOR projects. Actual values vary from project to project, from approximately 0.5 to 6 production wells per injection well. However, most projects cluster in the 1-3 well range, so this 1:1.5 ratio appears to represent the majority of (U.S.) EOR projects relatively well. It is unclear whether EOR projects in China are likely to experience fundamentally different conditions requiring more or fewer production wells relative to injection wells, but there is little evidence to date to suggest that this average relationship will vary significantly. Additionally, it is understood that it may not always be necessary to drill new wells for an EOR project, and that only the recompletion of existing production wells may be needed for some or all of the injector wells. Therefore, even if a higher ratio of wells may be required, it is unlikely that the project would bear the full cost drilling all new wells and the existing assumption should represent necessary costs reasonably well.

There is far less information available on ECBM production well requirements, simply because characteristics of coal seams are highly variable and there have been very few ECBM projects of sufficient size. In the North American cost curve study published by Dahowski et al. (2005), the authors assumed that each injection well required 2.5 production wells, based on the average ratios for two pilot projects in the U.S., including the Tiffany Unit (Colorado) and the Burlington Allison Unit (New Mexico), both in the San Juan Basin. The more recent ECBM pilot project undertaken by the Southwest Regional Carbon Sequestration Partnership is using 3 production wells and a single injection well (USDOE 2008), indicating a good fit between the previous assumption and current practice. For this study this production-to-injection well ratio of 3:1 is assumed for all modeled ECBM projects.

**CO<sub>2</sub> Recycling Costs** – For EOR and ECBM projects that inject CO<sub>2</sub> to enhance the recovery of oil or coalbed methane, a typical eventuality associated with these operations is that at some point following start of injection, CO<sub>2</sub> will begin to reach the production wells and be produced with the oil and gas, an occurrence known as “breakthrough” (see Figure 4.1). In most cases, and particularly where EOR and ECBM would be practiced for greenhouse gas mitigation benefits, after breakthrough, the CO<sub>2</sub> would need to be separated from the produced hydrocarbon stream and re-injected or recycled back into the formation. The costs of a recycling plant are significant, with Jarrell et al. (2002) reporting that “The CO<sub>2</sub>/H<sub>2</sub>S removal plant represented 62% of the total capital investment” for one west Texas CO<sub>2</sub>-EOR project, and that on average for several west Texas projects, the CO<sub>2</sub> recycling plant represents 22% of the total costs over the first ten years (second only to CO<sub>2</sub> purchases, which represent 68% of the total).

The costs associated with CO<sub>2</sub> recycling are estimated based on the method presented by Heddle et al. (2003) converted to units of tonnes of CO<sub>2</sub>. Based on analysis of the “typical project” presented in Jarrell et al. (2002) and shown in Figure 4.1, it was determined the average recycle rate over an EOR project’s lifetime is 76.5% (i.e., for each tonne of new CO<sub>2</sub> injected into the formation, 0.765 tonne is pumped to the surface with produced oil, separated and then recycled back into the formation). For costing purposes we assume that a recycling plant capable of handling 100% of the average input CO<sub>2</sub> stream should be built. Therefore, the capital cost associated with this plant is estimated as:

$$\text{Capital Cost (2003 USD)} = 23.66 * Q_{CO_2}$$

where  $Q_{CO_2}$  represents the annual average CO<sub>2</sub> flow rate in tonnes CO<sub>2</sub>/yr. For annual O&M costs, Heddle et al. (2003) proposed a cost function that equates to 16% of capital for operation and maintenance of the separations units and compression needs, and this is used here. Therefore, the total levelized cost for CO<sub>2</sub> recycling for EOR and ECBM projects applied in this study is \$6.39/tCO<sub>2</sub> in 2003 dollars (\$6.78/tCO<sub>2</sub> in 2005 dollars). This compares quite favorably with estimates found in the literature (KGS 2002, Ghomian et al. 2008) which suggest a value of \$0.35/mcf (\$6.62/tonne) of recycled CO<sub>2</sub>.

**Other Costs** – Even while accounting for well and CO<sub>2</sub> recycling costs, other costs associated with operating an EOR flood or ECBM project may still be unaccounted for – specifically additional infrastructure, operating and administrative costs associated with the development, management, and operations of such a project. Though costs can be highly variable, Kinder Morgan presents a graphical representation of the typical costs associated with a CO<sub>2</sub> EOR project on their website (Kinder Morgan 2009). While dated, it indicates that at a time when oil prices were approximately \$18/bbl operating costs (excluding CO<sub>2</sub> purchase costs) for a typical CO<sub>2</sub> flood might be about \$2.70/BOE or approximately 15% of the value of a barrel of oil. More recent costs reported for a SACROC development project totaled \$4.01/BOE for field facilities, infrastructure, and other (non CO<sub>2</sub> handling) operating costs, which for the

time represented over 14% of the value of a barrel of oil (Bradley 2004). Based on costs reported by Denbury Resources Inc. (2008 and 2009), lease operating expenses for their CO<sub>2</sub>-EOR operations over the past 6 years have averaged 22% and general and administrative costs 5% of the value of a barrel of oil. Comparing these operating costs to the existing operating costs already accounted for by the factors and assumptions noted above (including well and CO<sub>2</sub> handling expenses), it was estimated that additional operating and general and administrative costs not otherwise accounted for by the cost model likely represent approximately 15% of the assumed value of a barrel of oil equivalent. Thus, this factor has been applied to account for these extra costs for all EOR and ECBM projects evaluated in this analysis.

**Energy Prices** – In order to incorporate the offsetting revenues derived from co-produced oil and gas associated with CO<sub>2</sub> injection into oil- and gas-bearing reservoirs, the authors assumed future wellhead oil and gas prices based on the EIA Annual Energy Outlook forecasts for 2030 (EIA 2008b). Thus, (in 2006 dollars), \$60.59 per barrel of oil was assumed for the long-term wellhead oil price, and wellhead gas price was assumed to be \$6.63/mcf. Note that, although these represent values in the contiguous United States, the authors chose these values over imported values to more accurately reflect the cost of energy products without transport or refining cost components.

#### **4.4.5 Measurement, Monitoring and Verification**

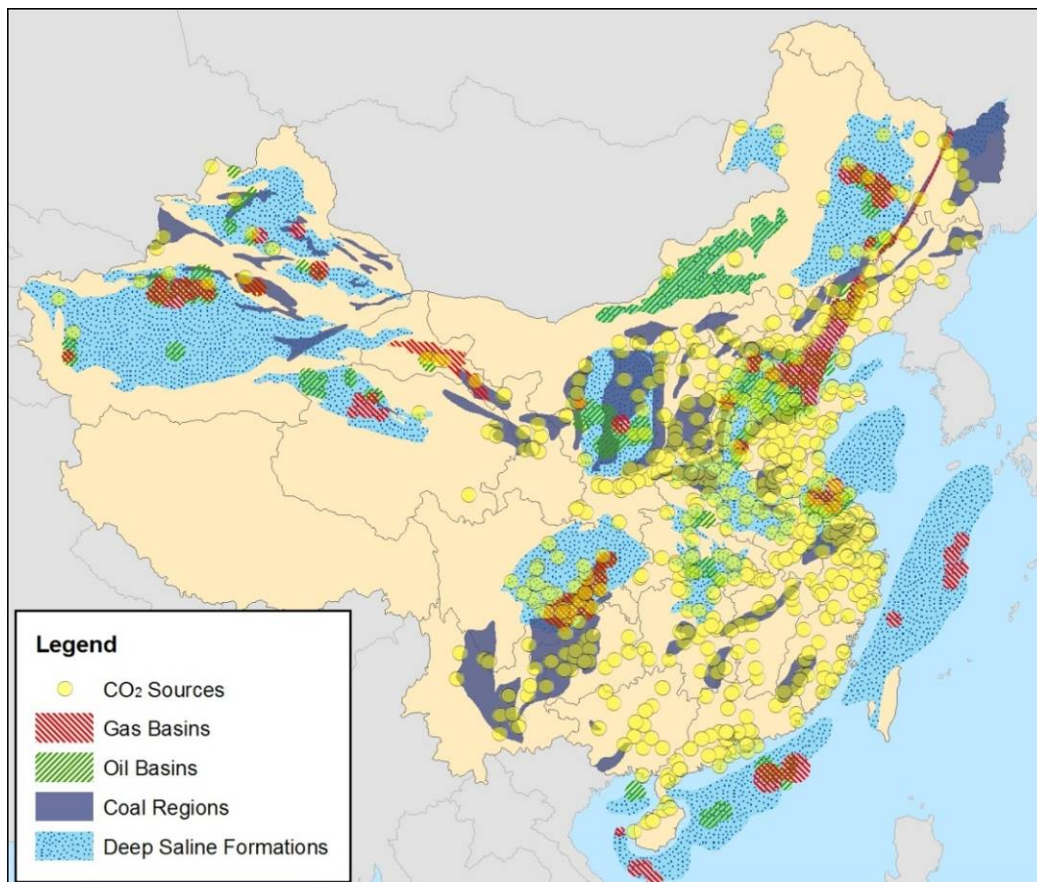
The goal of CCS is to ensure that CO<sub>2</sub> is safely and securely locked in deep geologic formations, away from the atmosphere, for meaningful timeframes – perhaps thousands of years. Therefore, an adequate measurement, monitoring, and verification (MMV) program is a critical component for any CCS system. The costs of MMV activities will likely vary significantly from project to project, and there remains a paucity of reliable data for a range of CCS project sizes and storage conditions. However, research published by Benson et al. (2005), estimated an approximate MMV cost of \$0.077/tCO<sub>2</sub> (discounted, in 2005 dollars) for their “enhanced” monitoring suite, which was the highest-cost case presented. This \$0.077/tCO<sub>2</sub> MMV cost was applied for this study. It is likely that smaller projects – where proportionately more monitoring infrastructure will be required per ton of CO<sub>2</sub> injected – will see higher than average levelized costs, while very large projects that can take advantage of economies of scale may see lower per-ton costs. It is also likely that projects injecting into very thick intervals, which will limit the areal spread of the CO<sub>2</sub> plume over the project lifetime, will encounter lower costs for areal monitoring techniques such as surface seismic, aerial gravimetric and magnetic, and atmospheric monitoring relative to projects injecting the same volume of CO<sub>2</sub> into a thinner interval. As these types of relationships are resolved by current and future pilot- and commercial-scale CCS projects, they can be incorporated into future iterations of this analysis. Still, even an order-of-magnitude variation around this assumed value is expected to have a relatively minor impact on the ultimate combined per-ton costs as assessed in this study.

## 5.0 CO<sub>2</sub> Source-Reservoir Matching and Cost Curves for CO<sub>2</sub> Transport and Storage

This section presents results from the geospatial and economic analyses performed on the CO<sub>2</sub> source and candidate geologic CO<sub>2</sub> storage data, including simple proximity analyses and a number of cost curves, including sensitivity analyses, for CO<sub>2</sub> transport and storage in China.

### 5.1 Proximity Analysis

One preliminary measure of how practical CCS technologies might be for a particular region or nation is how far candidate CO<sub>2</sub> storage reservoirs are from existing large CO<sub>2</sub> point sources. As Figure 5.1 shows, the map of large CO<sub>2</sub> point sources displayed against the set of candidate CO<sub>2</sub> storage reservoirs visually suggests a good overall spatial match between the sources and sinks within China.



**Figure 5.1.** Map of Large CO<sub>2</sub> Point Sources with Candidate Geologic Storage Formations

This initial impression is substantiated by more detailed proximity analysis, which also reveals some interesting relationships. Table 5.1 lists the results of the proximity analysis for China, by the percentage of sources having at least one candidate CO<sub>2</sub> storage formation within each of the specified distances. For example, of the total 1,623 large CO<sub>2</sub> point sources in China that were modeled in this study, 54% of the

sources and 50% of the total emissions have a candidate storage formation in their immediate vicinity, which might be accessible via a very short transport distance to a suitable injection site. Eighty-three percent of the sources have at least one storage formation within 80 km (50 mi), and a full 91% of the sources, representing 89% of the total emissions from the large CO<sub>2</sub> sources, have the potential to reach a candidate storage formation within 160 km (100 mi). The maximum distance from a CO<sub>2</sub> source to its nearest potential onshore storage formation is approximately 375 km (230 mi), for a source located on the coast of Guangdong Province in the South Central region and its nearest candidate storage reservoir, the Chenzhou-Zixing coal-bearing region in southeastern Hunan Province. Overall, there are just nine large CO<sub>2</sub> point sources whose distance to one of the candidate storage reservoirs examined in this analysis exceeds 320 km (200 mi), all of them located in the South Central region. Together, this implies that most CO<sub>2</sub> sources in China can be connected with geologic storage options with little need for extensive and costly long distance pipeline infrastructure.

**Table 5.1.** Proximity Analysis Results for China (Number of Large CO<sub>2</sub> Point Sources within Specified Distance to Candidate Onshore Storage Reservoirs)

	<b>China Total</b>
Total Sources	1,623
0 km to Storage Reservoir	54%
Within 80 km (50 mi)	83%
Within 160 km (100 mi)	91%
Max. Distance to Storage Reservoir	375 km (230 mi)

Table 5.2 lists similar results for each of the six administrative regions. These results confirm what is apparent from visual inspection of the data on a map – that sources in certain regions of China have closer access to potential CO<sub>2</sub> storage reservoirs than others. In regions such as the North, Northwest, and Southwest, there is a good spatial correlation between CO<sub>2</sub> sources and nearby candidate storage formations, with nearly all sources having at least one potential storage option within just 80 km. On the other hand, areas of the South Central and East regions, and particularly areas near the coast, are considerably farther from candidate onshore CO<sub>2</sub> storage formations. As noted previously, near offshore sub-seabed formations may provide valuable supplemental capacity for these highly industrialized coastal regions; however, detailed examination of these offshore basins was outside the scope of this current work.

**Table 5.2.** Proximity Analysis Results for Six Regions of China (Number of Large CO<sub>2</sub> Point Sources and Percentage within Specified Distance to a Candidate Onshore Storage Reservoir)

	<b>East</b>	<b>North</b>	<b>Northeast</b>	<b>Northwest</b>	<b>South Central</b>	<b>Southwest</b>
Total Sources	588	254	159	129	349	144
0 km to reservoir	40%	67%	52%	58%	52%	88%
Within 80 km	80%	98%	86%	99%	65%	94%
Within 160 km	94%	100%	91%	99%	72%	100%
Max. Distance to Storage Reservoir	300 km (185 mi)	110 km (70 mi)	190 km (120 mi)	300 km (185 mi)	375 km (230 mi)	145 km (90 mi)

## 5.2 Cost Curves for CO<sub>2</sub> Transport and Storage in China

The computation of cost curves for CO<sub>2</sub> transport and storage in China was performed following the methodology and assumptions described in Chapter 4. Each of the 1,623 large CO<sub>2</sub> sources was matched to each candidate CO<sub>2</sub> storage reservoir that could be reached within the specified maximum search radius, which in this analysis was set to 240 km (150 mi). For each resulting pair, the costs of CO<sub>2</sub> transport and the various components of CO<sub>2</sub> storage were estimated, based on the combined characteristics of the individual source and selected reservoir. A least-cost optimization process was performed to determine which sources would be allowed to store their CO<sub>2</sub> into which target reservoirs, subject to filling constraints over a 20-year period.

There are several key points to bear in mind when reviewing the cost curve results:

- The cost curves are built on a modeling approach shaped by the assumption of an economy-wide signal precipitating immediate deployment of CCS at all large CO<sub>2</sub> sources. This provides a useful starting point from which to evaluate the full CO<sub>2</sub> storage capacity that could be demanded, and at what costs, subject to characteristics of both the candidate storage reservoirs and the CO<sub>2</sub> sources that might wish to access them. The application of this approach is purely a mechanism to facilitate the generation of cost curves and is not intended in any way to represent a realistic or suggested deployment scenario for China.
- Each individual point on the curve represents a unique CO<sub>2</sub> source and its final selected CO<sub>2</sub> storage reservoir. The amount of CO<sub>2</sub> stored into the formation each year appears on the x-axis (in units of MtCO<sub>2</sub>/yr) represents the mass of CO<sub>2</sub> that is supplied from the source to the storage reservoir annually over the entire 20-year storage commitment term for the project. The y-axis indicates the estimated net cost for CO<sub>2</sub> transport and storage (in units of \$/tonne CO<sub>2</sub>) for each resulting pair, consisting of specific cost components that include: transport, site characterization, injection, MMV, plus production costs and any offsetting revenues resulting from EOR or ECBM projects.
- The cost curves presented here intentionally exclude costs for CO<sub>2</sub> capture, dehydration, and compression. Such costs can be incorporated into the analysis at a later time and the curves regenerated. However, at this time, the focus is on the net cost of CO<sub>2</sub> transport and storage, including any revenues potentially resulting from enhanced oil or coalbed methane recovery.
- Areas of the curve that fall below the x-axis indicate potential source-sink combinations that result in *negative* net costs for transport and storage (i.e., net cost of less than \$0/tCO<sub>2</sub>). In all cases, these represent projects that inject CO<sub>2</sub> into depleted oil fields or coal seams in which the value of the recovered oil or coalbed methane is sufficient to offset the positive costs associated with the project. However, it is important to bear in mind that when costs of capture, dehydration and compression are added, the resulting costs may or may not remain negative. Also, many of these “value-added” formations may not be ready for CO<sub>2</sub> injection immediately and the timing of reservoir availability along with more specific reservoir conditions would need to be evaluated on a project-by-project basis to confirm the potential for success of these options. For example, see Dahowski and Bachu (2006) for a discussion of how these timing issues can impact the utilization of value-added reservoirs.

- Although the CO<sub>2</sub> transport and storage cost curves for China were created based on the same CO<sub>2</sub> source-reservoir matching and cost curve methodology that was developed and applied previously for North America as well as the U.S. (Dahowski et al. 2005, Dooley et al. 2006), care must be exercised when comparing the results of these studies. While the same core methods and modeling framework were applied in both studies, the development of the China cost curves incorporated a number of significant improvements, particularly to various components of the cost model. These changes reflect the combined impact of improved parameterization of CCS requirements and costs, and experience in modeling such systems that has been gained since completion of the earlier work. As a result, the cost curves for China are not directly comparable to those previously published for North America and the U.S. However, plans are underway to apply the updated assumptions and cost models to generate new cost curves for the U.S. that will enable comparative analyses of CCS deployment costs between these two important regions.

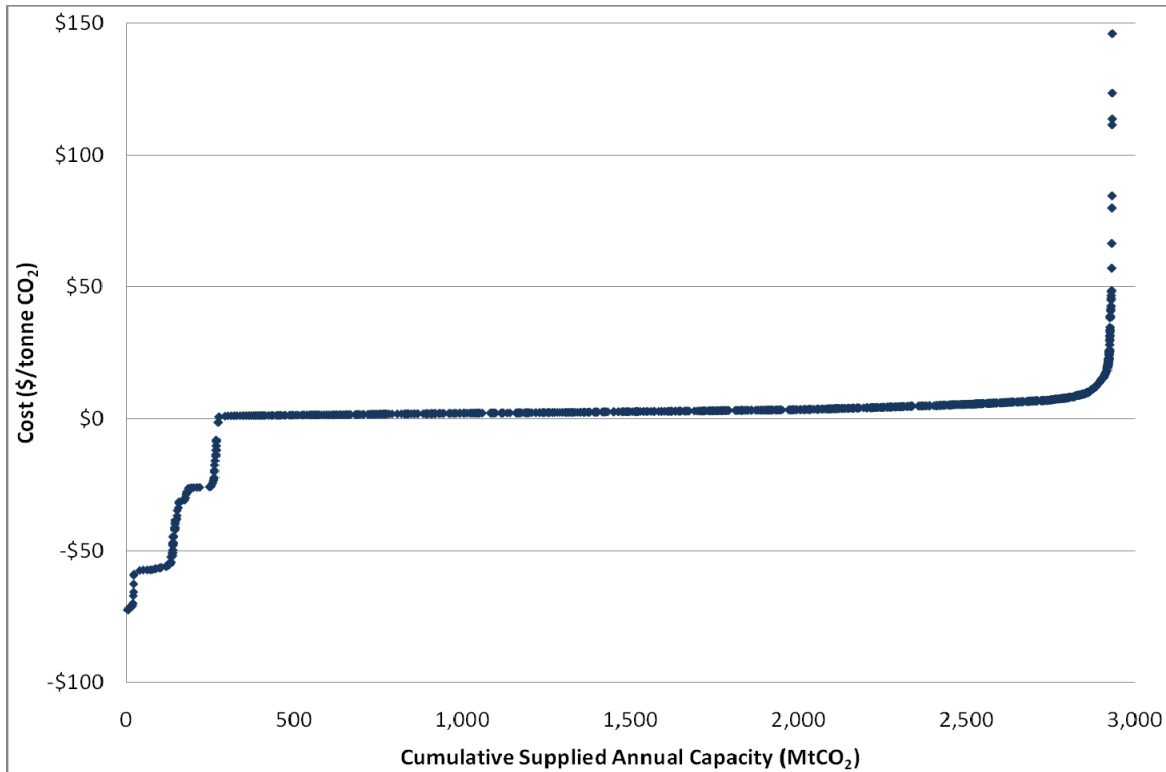
As noted, the methodology underlying the development of the CO<sub>2</sub> storage supply curves is based on an assumption that all large CO<sub>2</sub> point sources within the modeled dataset employ CCS technologies and simultaneously seek out their lowest-cost storage option. While this is not likely to occur in reality, the assumption enables an understanding of how the market for CO<sub>2</sub> storage capacity might evolve in China should CCS technologies begin to deploy broadly. Supply curves such as these are widely used in the world of greenhouse gas mitigation analysis because they quickly and easily communicate information on the magnitude of CO<sub>2</sub> mitigation potential available at a given price, and provide a means to compare the relative costs and impact of different mitigation options. As CCS deployment is likely to start with those opportunities that have the lowest average per-ton mitigation cost, the curves presented here are useful in evaluating how CCS might deploy within the broader portfolio of mitigation options, over time and under a variety of economic scenarios and associated CO<sub>2</sub> price paths. Furthermore, the nature of the technical and economic foundation on which the curves are constructed allow researchers a useful means with which to evaluate how a variety of real-world factors and characteristics might impact overall costs and deployment potential.

### **5.3 Cost Curve Results – Reference Case**

The Reference Case cost curve for CO<sub>2</sub> transport and storage representing the first 20 years of large-scale deployment in China is presented in Figure 5.2. The Reference Case incorporates the base technical and economic assumptions described in Chapters 2, 3, and 4 of this report.

The Reference Case cost curve for CO<sub>2</sub> transport and storage in China consists of three main parts. First, moving left to right, there is a set of steps in the negative cost part of the curve, moving from approximately -\$72/tCO<sub>2</sub> to \$1/tCO<sub>2</sub>. This region of the curve is generally characterized by large CO<sub>2</sub> sources selecting value-added storage formations that are nearby and exhibit promising hydrocarbon recovery characteristics. Many of these storage formations are oil fields with good potential for EOR and others are unmineable coal seams with strong expectations for ECBM response. The 94 pairs in this first part of the curve account for 275 MtCO<sub>2</sub> of stored CO<sub>2</sub> per year, or 7% of the total CO<sub>2</sub> emitted from the entire set of CO<sub>2</sub> point sources.





**Figure 5.2.** Cost Curve for CO<sub>2</sub> Transport and Storage in China

The next and largest part of the curve is a long, slowly increasing stretch that spans the next 2,600 MtCO<sub>2</sub>/yr of stored CO<sub>2</sub>, from just under \$1/tCO<sub>2</sub> to approximately \$10/tCO<sub>2</sub>. The 1,020 pairs in this region consist of a broad mix of source types and storage reservoir classes. However, the overwhelming majority are large sources storing their CO<sub>2</sub> into the large, high-capacity deep saline formations that are broadly distributed throughout many parts of China. The CO<sub>2</sub> stored within this range of costs represents two-thirds of the total CO<sub>2</sub> generated by all of the sources included in this analysis and indicates that there is significant potential for many of China's large CO<sub>2</sub>-emitting facilities to utilize nearby deep saline formations for emissions reductions.

The last major part of the curve is a nearly vertical upward-trending tail which indicates quickly increasing transport and storage costs. This section begins at about \$10/tCO<sub>2</sub> and ends near \$145/tCO<sub>2</sub>. The 254 pairs that make up this tail section of the curve consist of much smaller CO<sub>2</sub> sources, each producing on average one tenth as much CO<sub>2</sub> per year as is typical for the sources within the first two sections of the curve. Not only are these much smaller sources already facing higher per-tonne costs for equivalent transport and storage, but they also tend to be farther from their matched storage reservoirs and therefore require longer pipelines: 135 km (84 miles) on average or over twice as far as the average for the pairs in the middle part of the curve.

In all, the 1,368 pairs depicted by the Reference Case cost curve represent over 2,900 MtCO<sub>2</sub> that may be stored each year in candidate CO<sub>2</sub> storage formations within the maximum specified 240 km (150 mi) search distance over the first 20-year period considered here. Missing altogether from the curve are two other groups of CO<sub>2</sub> sources:

- **Stranded Sources:** The first of these are the sources that had one or more storage formations within the 240 km search radius but were not able to gain access to their storage capacity because it had all been spoken for by other sources with lower net costs. These sources have potential storage formations nearby, but the capacity available to them is inadequate to satisfy the storage needs for these sources, even in the first modeling period. There are 188 sources that fall into this category, left stranded because the reachable storage capacity had been reserved by other sources, leaving a total of 361 MtCO<sub>2</sub>/yr to be vented that otherwise would have been stored underground. Most (83) of these stranded sources are located in the South Central region of China, with 50 in the East, 35 in the Southwest, 19 in the Northwest, and 1 in the Northeast. All of the sources in the North region were able to access sufficient CO<sub>2</sub> storage capacity in this analysis.
- **Excluded Sources:** The other group of sources consists of those with no candidate CO<sub>2</sub> storage reservoirs within the 240 km (150 mi) distance. These sources had no option of pairing with any storage reservoirs and therefore were not considered in the pairing and filling analyses. Across all regions of China there were just 67 large CO<sub>2</sub> sources in this category. Fifty-nine of these sources are located in South Central region, and most in the coastal province of Guangdong.<sup>1</sup> Another seven excluded sources are located in the East and one in the Northwest region of China.

The results of the Reference Case analysis for the first 20 years of large-scale CCS deployment in China are quite promising. The resulting cost curve suggests that the abundant geologic CO<sub>2</sub> storage resource estimated for China may be accessible by the majority of large CO<sub>2</sub> point sources within moderate transport distances. While there are both some very high resulting net transport and storage costs as well as opportunities for low and possibly negative cost storage, the vast majority of source-sink pairs comprising the curve exhibit net transport and storage costs between \$2-8/tCO<sub>2</sub>.

### 5.3.1 Sample Source-Sink Pairs within the Reference Case Cost Curve

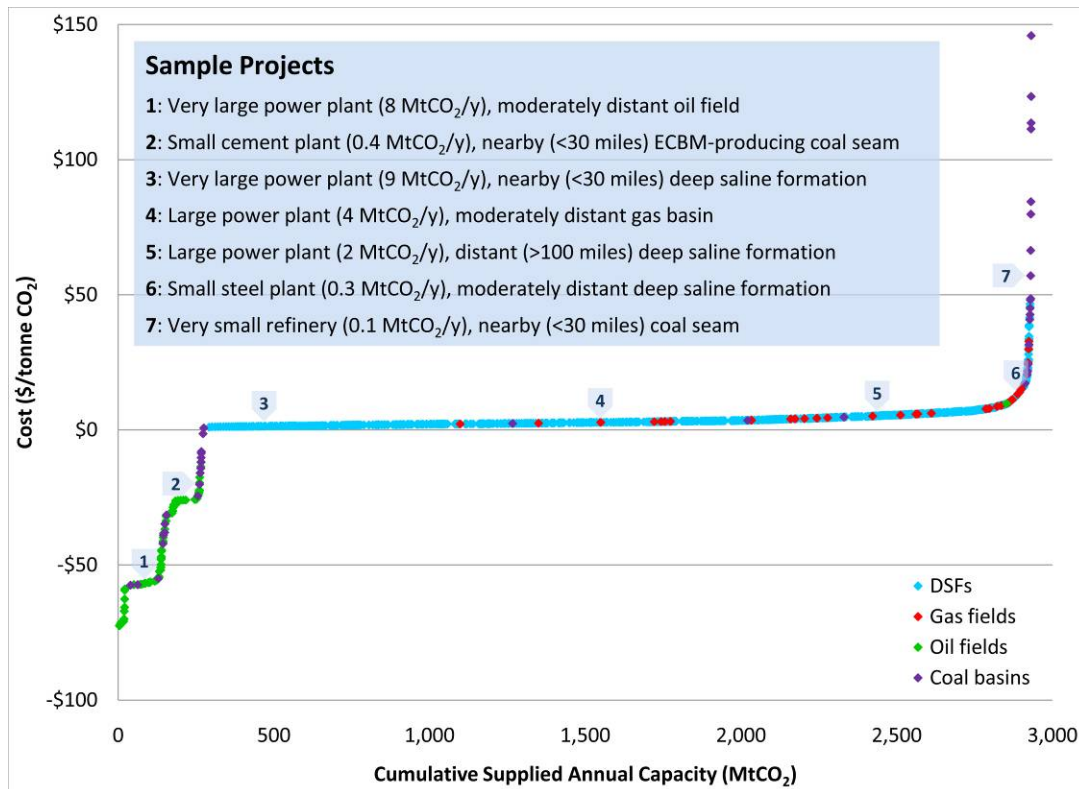
As noted above, each cost curve for CO<sub>2</sub> transport and storage presented in this report represents the set of individual large CO<sub>2</sub> point sources and their matched candidate geologic storage reservoir. Each point on the curve therefore corresponds to a specific CO<sub>2</sub> point source and its lowest-cost accessible storage option subject to the requirements and constraints described earlier, and the position of the point on the curve identifies both the estimated net cost of CO<sub>2</sub> transport and storage as well as the magnitude of CO<sub>2</sub> stored each year as a contribution to the cumulative storage from all possible pairings. Each of these pairings is essentially a potential real-world CCS deployment project, a detail that is easily missed when looking at the curve as a whole.

To illustrate this, the cost curve shown in Figure 5.3 includes information on seven sample points from the Reference Case curve. These sample points were selected to represent the types of CO<sub>2</sub> source and storage reservoir pairings that are typical of different parts of the curve. The location of each of the highlighted points is marked by a numbered box where the number corresponds to the brief description of each point in the legend. The curve itself is the same as shown in Figure 5.2, but in addition to identifying the seven sample pairs, Figure 5.3 is also color-coded to indicate the type of CO<sub>2</sub> storage

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<sup>1</sup> As noted previously, this analysis has focused on evaluating opportunities for CO<sub>2</sub> storage in onshore basins in China. There are some sub-sea basins just off the coast of China that may offer additional storage options for these and other stranded sources that are located along the coastal zones. It is recommended that future analyses examine this possibility in greater detail.

reservoir used in each pairing. This sink type disaggregated cost curve clearly shows that the negative costs at the low end of the curve are achieved by utilizing storage in depleted oil fields with EOR potential and coal seams with ECBM potential, and that the majority of the curve is based on storage into deep saline formations.

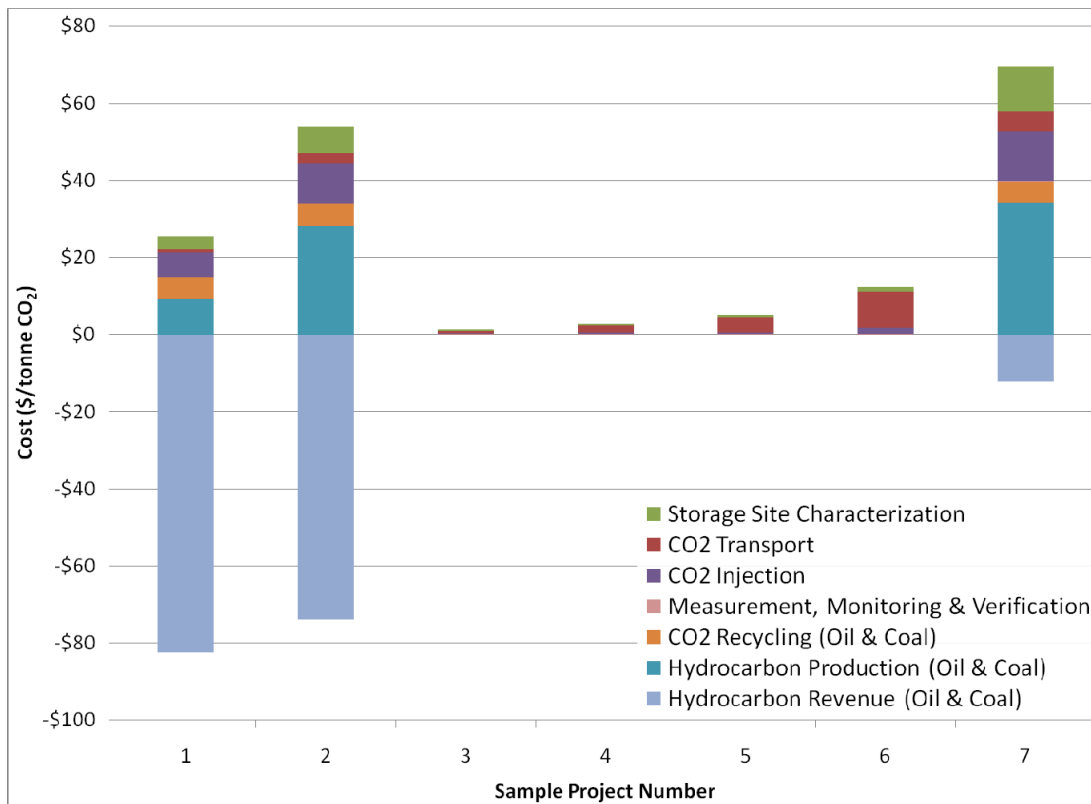


**Figure 5.3.** Reference Case Cost Curve Colored by Sink Type with Sample Project Callouts

It is also important to recognize that the estimated costs shown on each curve are the total net transport and storage costs, consisting of each of the individual cost components discussed in Chapter 4. The costs displayed by the curve are therefore the sum of the individual cost components which can vary significantly based on the unique combination of characteristics for each individual source-reservoir pair. The component-level costs for the seven sample points are shown in Figure 5.4, indicating the contribution from site characterization, pipeline transport, injection, monitoring, and potential costs and revenues associated specifically with enhanced hydrocarbon recovery.

Sample points 1, 2, and 7 on the curve all represent projects incorporating CO<sub>2</sub> storage into value-added reservoirs. However, only in the first two do estimated revenues from enhanced oil and methane recovery exceed the cumulative costs associated with site characterization, CO<sub>2</sub> transport, injection, recycling, production, and MMV. Site characterization costs for these three projects are also higher than for the other projects, due to the lower per-well injection rates and larger areal extent per unit of injected CO<sub>2</sub> for a typical EOR or ECBM project. For the remaining four sample projects, CO<sub>2</sub> transport, injection, and site characterization constitute the largest cost components. Differences in pipeline transport costs are driven primarily by the distance from the source to the selected reservoir as well as the flow rate of CO<sub>2</sub>. Though a higher flow rate can increase the diameter of pipeline required, there are economies of scale as well as amortization factors that drive the per-tonne costs down for larger transport

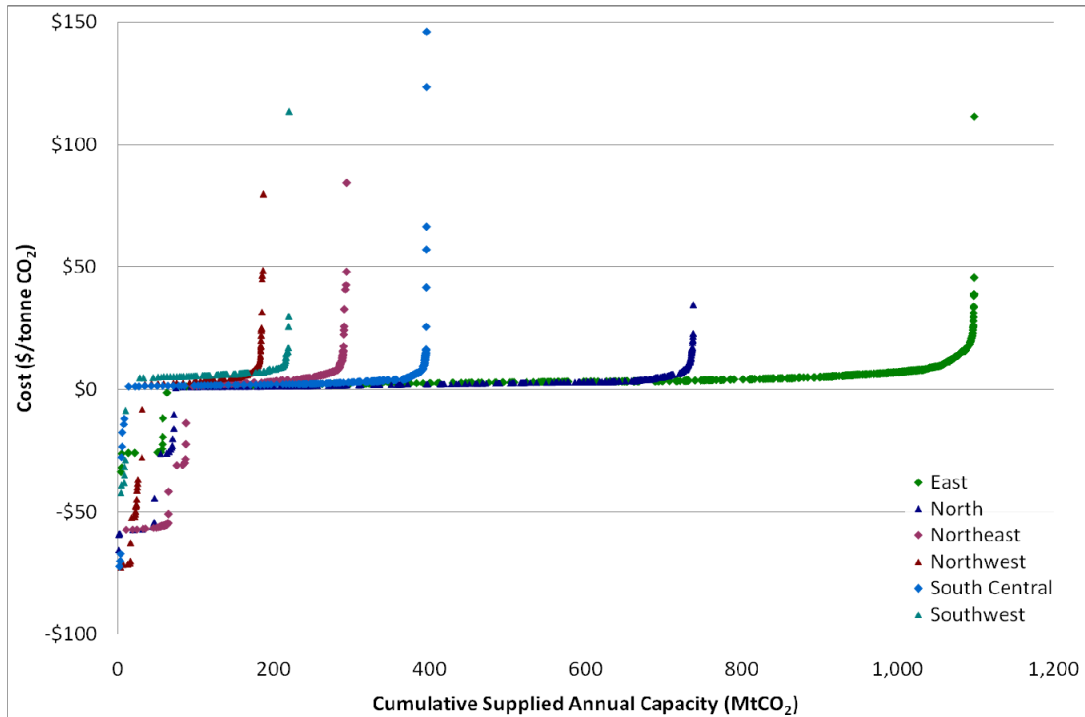
flow rates. This is why the resulting transport cost for project 3, with a 9 MtCO<sub>2</sub>/y flow rate and shortest transport distance, is the lowest, and why the transport cost for project 6 is greater than project 5 even though the transport distance is considerably longer for project 6.



**Figure 5.4.** Disaggregated Component Costs for the Seven Sample Projects

### 5.3.2 Regional Cost Curves – Reference Case

Another valuable characteristic of these cost curves is that they allow examination of potential CCS opportunities in a variety of ways. Figure 5.5 shows CO<sub>2</sub> transport and storage cost curves for each of the six major regions of China. This provides a more detailed look at the demand for and costs of CO<sub>2</sub> storage across different parts of the country, where characteristics of the economies, energy and industrial infrastructure, as well as geology contribute to varying results. These cost curves resulted from the same type of analysis and procedure described for the single aggregate cost curve above, split out into a more detailed view to highlight the unique CCS deployment potential and range of costs within each region. The first thing that stands out is the relative difference in total potential annual demand for CO<sub>2</sub> storage from one region to the next. The East region has the largest number of sources and the most CO<sub>2</sub> paired with nearby prospective CO<sub>2</sub> storage formations; and the Northwest has the fewest. The Southwest region has only one more paired CO<sub>2</sub> source than the Northwest, yet overall the sources are larger and 36 MtCO<sub>2</sub> more is modeled to be stored there per year, even though a larger number of sources are also left stranded. The South Central region's curve spans the widest range of net transport and storage costs, from -\$72 - \$146/tCO<sub>2</sub> with the North region having the narrowest, with peak costs at \$35/tCO<sub>2</sub>.

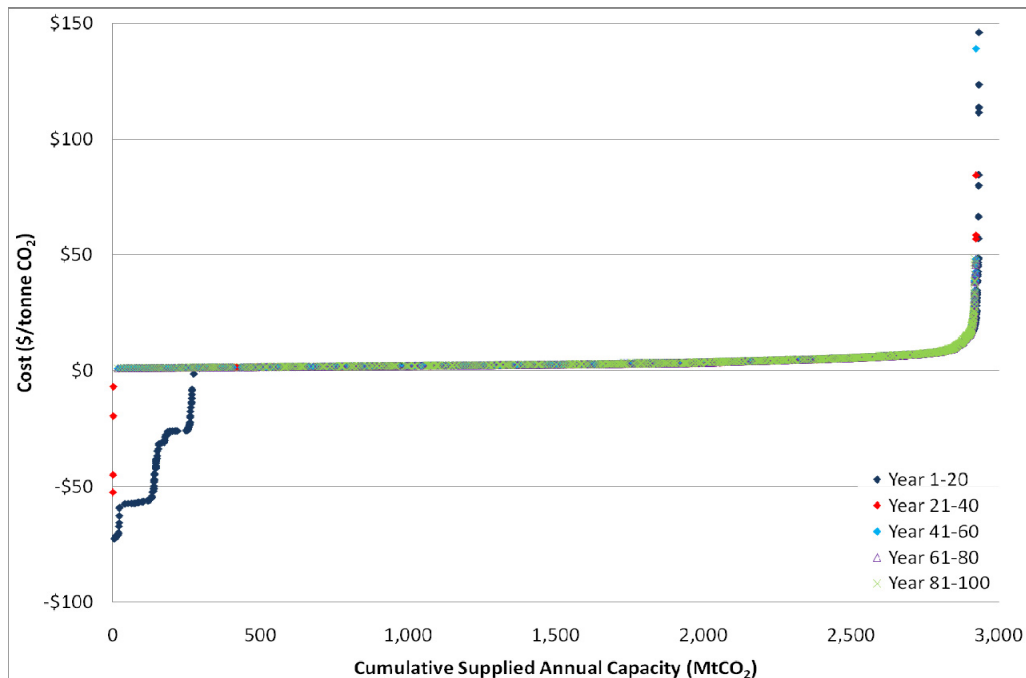


**Figure 5.5.** Individual CO<sub>2</sub> Transport and Storage Cost Curves for Six Regions of China, Reference Case - First 20 Year Analysis Period

### 5.3.3 Time Series Cost Curves – Reference Case

Each of the cost curves presented to this point have been for the first analysis period – the first 20-year period of full scale CCS deployment in China as modeled here. The results indicate how much CO<sub>2</sub> can be stored annually and at what transport and storage cost, for each source-reservoir pair, based on a constraint that the storage reservoir must be able to take 20 years of the source’s CO<sub>2</sub>. However, in order to better understand the longer-term potential for CCS to deploy in China it is necessary to examine periods beyond the first 20 years, considering the progressive filling of each of the selected storage reservoirs over time.

The Reference Case cost curves for each of the first five analysis periods are shown in Figure 5.6. Together, these represent the resulting curves covering 100 years of full-scale CCS deployment in China. While it is difficult to differentiate between most of the curves, this in itself suggests a significant finding: under the Reference Case scenario, there appears to be abundant CO<sub>2</sub> storage capacity in China such that the total annual mass of CO<sub>2</sub> being stored does not change appreciably from year 1 through year 100. This is an important result and indicates that the geologic CO<sub>2</sub> storage resource in China is sufficiently robust and geographically distributed to handle more than 100 years of large-scale CCS deployment as modeled in this analysis. Moreover, not only is there little change in the total annual mass of CO<sub>2</sub> being stored as reservoirs fill, but the costs of transport and storage also do not increase significantly over this century of deployment.

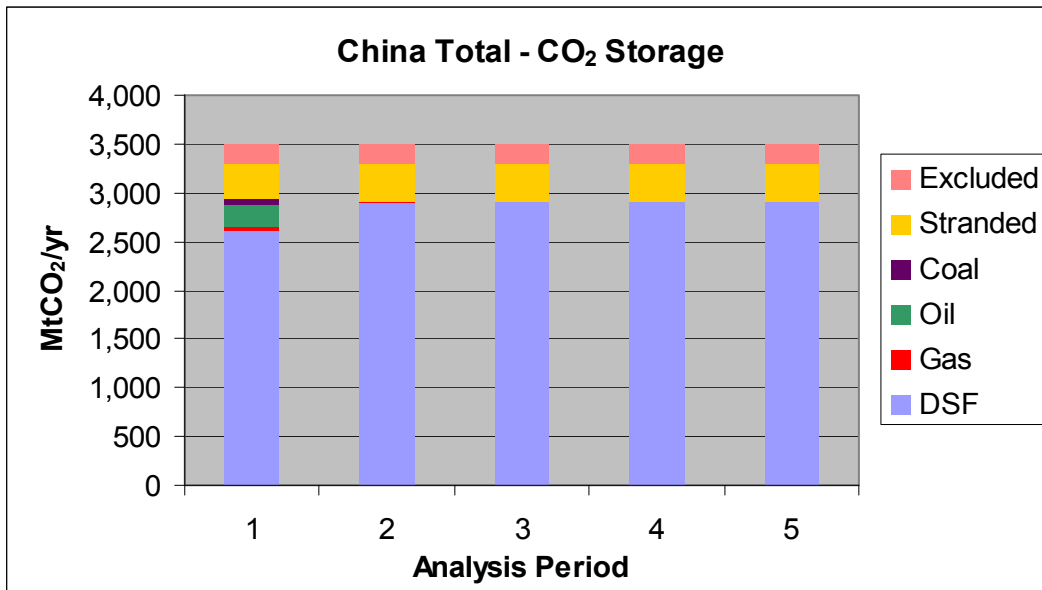


**Figure 5.6.** Reference Case Cost Curves for 100 Years of Full-Scale Deployment

The only major differences in the resulting temporal cost curves are evident at the two ends of the curves. The most pronounced difference is visible at the low (left) end of the curve, where the very low / negative cost part of the curve disappears rather quickly. Within the first 20-year analysis period, as much as 273 MtCO<sub>2</sub>/yr of negative net-cost transport and storage options are available and utilized by 93 CO<sub>2</sub> sources. However, the results indicate that within the second 20-year analysis period only 2.3 MtCO<sub>2</sub>/yr can be accessed by just 4 sources, and by the end of the first 40 years, the capacity of all of the negative net cost storage options have been filled to a degree that they can no longer accept sufficient quantities of CO<sub>2</sub> to meet the 20-year commitment requirement (see Section 4.1) in following periods. This finding further underscores the need to address issues such as the timing of availability for potential EOR and ECBM opportunities, to build a more accurate picture of the prospects for low-cost storage over time and to better identify the true early deployment opportunities or “low hanging fruit.” It is also worth noting here that as the available capacity in the value-added storage reservoirs is exhausted after the first 20 years, the CO<sub>2</sub> storage demand that had been met by them is largely taken up by nearby deep saline formations.

More subtle differences are evident on the right end of the curves. Here, particularly above the \$50/tCO<sub>2</sub> range, there is some clear differentiation between points on the curves. This is the result of some shifting at the very highest part of the curves, consisting of very small sources competing to reach rather distant storage reservoirs. The differences reflect the modeling result that a number of these very high cost, marginal value potential CCS projects are losing their ability to access suitable storage space over time, as reservoirs fill and competition for available space increases. These sources generally have few options for storing their CO<sub>2</sub> and a small increase in competition from other sources can quickly leave them stranded. The impact of stranded sources can be seen on the curves between approximately the \$10-50/tCO<sub>2</sub> range. Nearly imperceptible, this again reflects the robust nature of the overall CO<sub>2</sub> storage resource in China, even though the highly demanded value-added storage options may not last very long.

Figure 5.7 shows the changing nature of the CO<sub>2</sub> storage supply over the 100 years of analysis for the Reference Case. The stacked bar for analysis period 1 presents the amount of CO<sub>2</sub> storage provided during the first 20-year analysis period by reservoir class. Of all of the captured CO<sub>2</sub> on offer each year, 75% (2,623 MtCO<sub>2</sub>) is stored in deep saline formations, 6% in depleted oil fields, 2% in unmineable coal seams, and less than 1% in depleted gas fields; 10% (361 MtCO<sub>2</sub>) was not able to access suitable storage capacity within the 240 km search radius and was left stranded, and 6% (210 MtCO<sub>2</sub>) was completely excluded from the analysis due to having no storage reservoirs available within 240 km. In the second analysis period, only 2.3 Mt CO<sub>2</sub>/yr is stored in depleted oil fields, 25 MtCO<sub>2</sub>/yr in depleted gas fields, 3.7 MtCO<sub>2</sub>/yr in coal seams, and an additional 9 MtCO<sub>2</sub>/yr is left stranded; modeled storage in deep saline formations rises to 83%. By the fifth 20-year analysis period, DSFs are the only type of reservoir being utilized, taking just over 83% of the CO<sub>2</sub> each year, and stranded CO<sub>2</sub> has increased to just 373 MtCO<sub>2</sub>/yr. Similar representations of the CO<sub>2</sub> storage supplied over the 100 years for each region modeled here are shown in Figure 5.8. Figure 5.9 illustrates the modeled filling of individual storage basins over time, under this Reference Case scenario, where the different colors represent the degree to which each formation has been filled at the end of each 20-year analysis period.



**Figure 5.7.** 100 Years of CO<sub>2</sub> Storage by Reservoir Class – Reference Case

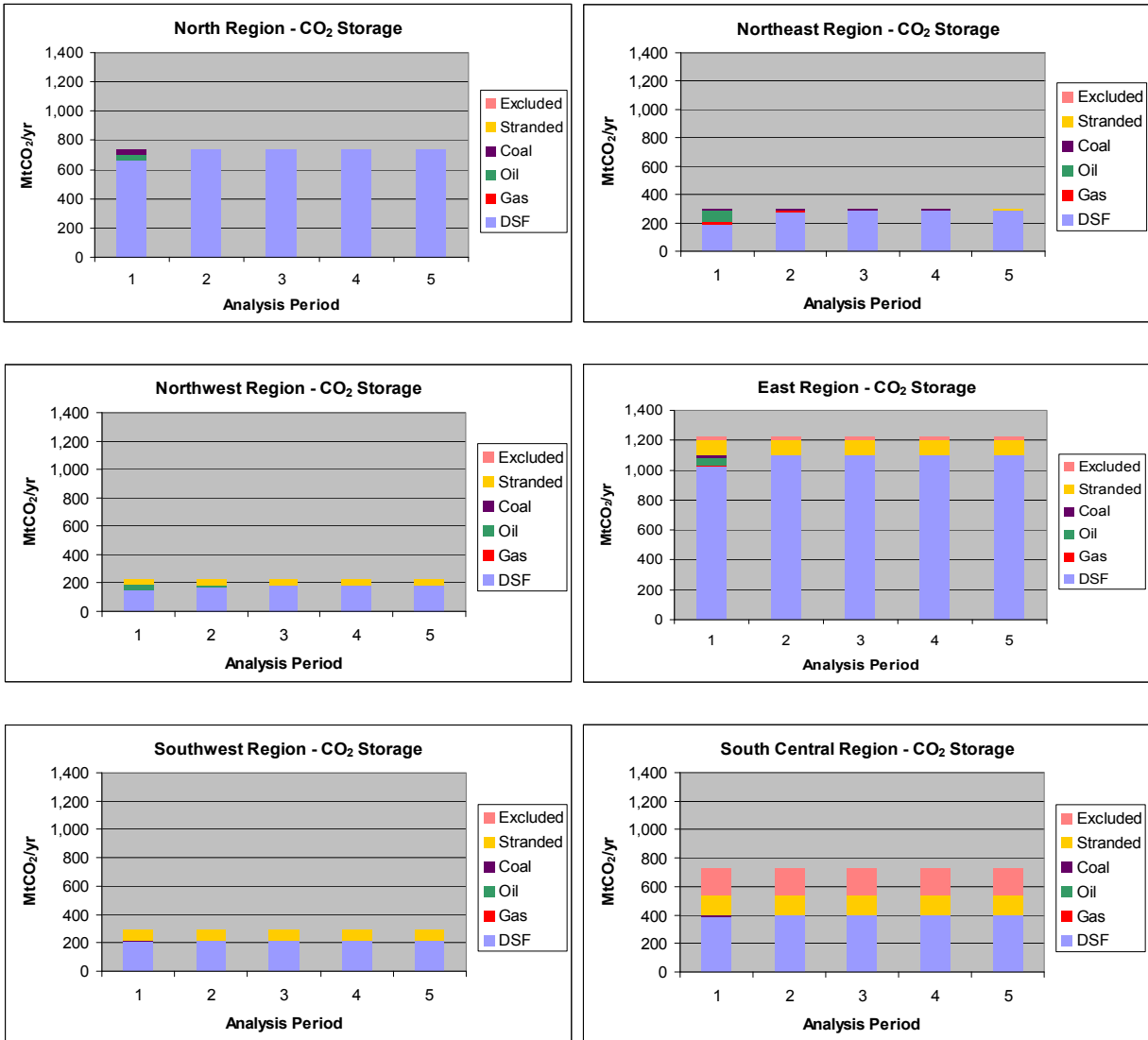
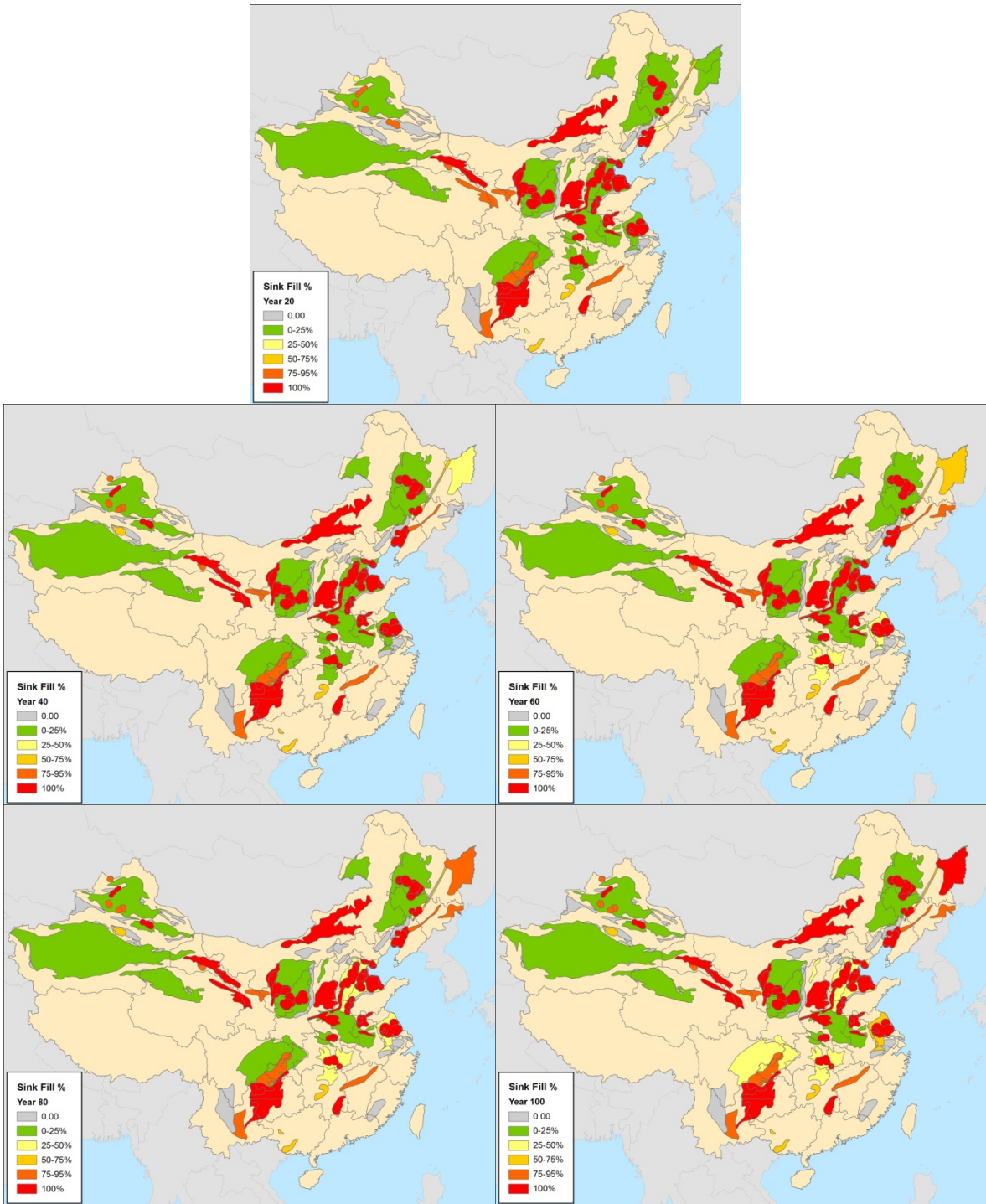


Figure 5.8. 100 Years of CO<sub>2</sub> Storage by Reservoir Class and Region – Reference Case





**Figure 5.9.** Mapping Reservoir Filling over 100 Years of Storage – Reference Case

## 5.4 Sensitivity Analyses

While the results from the Reference Case analyses indicate that there is significant potential for CCS technologies to deploy broadly and economically across most industrial sectors and geographic regions of China, there remains a good deal of uncertainty related to aspects of this very early stage of research. A variety of sensitivity analyses can be performed with the cost curves to better assess major drivers of costs and availability of storage capacity over time, and test the impacts of altering some of the key assumptions and parameters. In the previous section, an examination of the time series cost curves revealed how the lowest-cost storage formations (generally the value-added EOR and ECBM formations) are highly sought after by sources and fill up quickly; as a result, the initial spike in negative storage potential quickly dissipates and disappears as additional time periods are modeled. Here, we focus on two drivers which are likely to have some of the greatest impact on the magnitude of the CCS deployment potential and associated costs in China.

### 5.4.1 Reduced Storage Capacities

The Reference Case analyses were all based on the availability of more than 2,300 GtCO<sub>2</sub> of total estimated theoretical onshore CO<sub>2</sub> storage capacity, as detailed in Chapter 3. While the authors believe that this represents a conservative measure of the theoretical storage capacity for China, these are early estimates based on basin level parameters and assumptions which will require more detailed investigation and validation through in-depth field and laboratory studies. Additionally, a number of technical and societal constraints will likely combine to reduce the fraction of total theoretical CO<sub>2</sub> storage capacity that can be accessed and utilized for safe, long-term storage. Some capacity may be determined to be unsuitable for a variety of reasons including the presence of complex geology, faulting and seismic hazards; protection of underground drinking water supplies, cultural or environmentally sensitive areas; and other reasons which may make storage in certain areas either technically, economically, or socially unviable.

These determinations will require a much more detailed survey and characterization of the storage resource, along with a maturation of the necessary supporting economic and regulatory structures. Indeed, many of these constraints can only be adequately addressed at the local and site levels. However, in order to analyze the potential impacts that a reduced supply of accessible storage capacity might have on the costs and the ability to successfully deploy CCS in China, we examine the cases in which only 50%, 10%, and 1% of the estimated theoretical capacity is available for CO<sub>2</sub> storage. These capacity values, while likely on the low to extremely low end of what may be anticipated, were selected to test the robustness of the CO<sub>2</sub> storage resource in China and its ability to offer a meaningful option for emissions reduction and climate protection for this fast-growing economy.

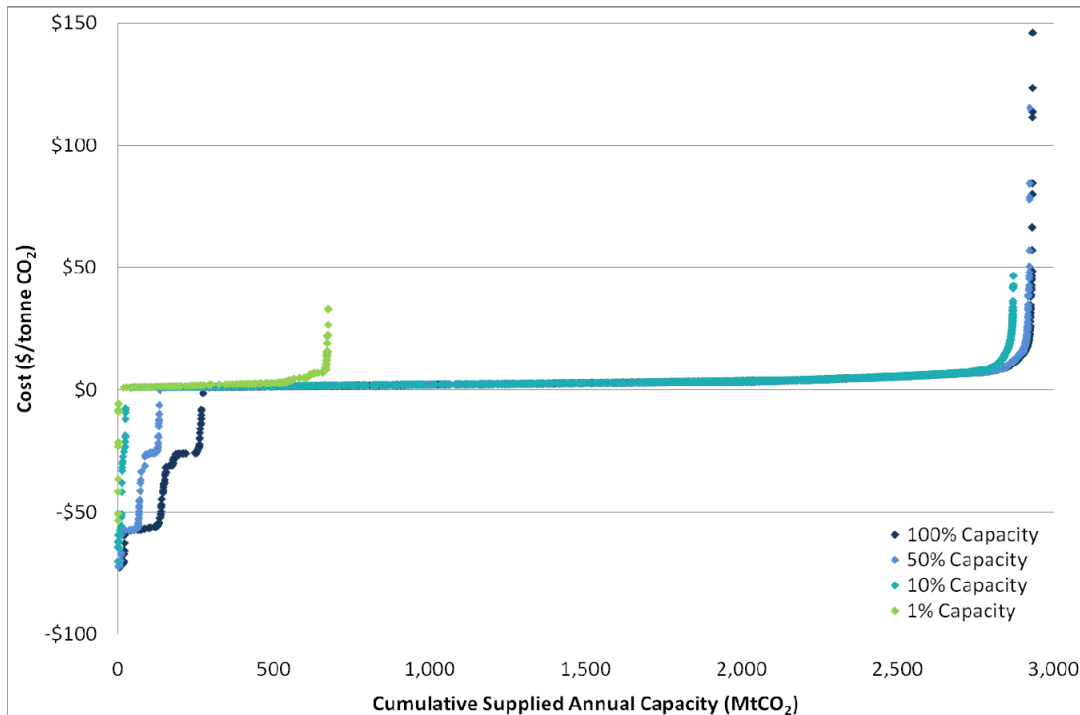
For this analysis, individual formation and basin capacities were reduced by an equal fraction so that only 50%, 10% or 1% of the total initial capacity was available in each case respectively.<sup>2</sup> The resulting cost curves for these analyses are shown together in Figure 5.10. Here, the transport and storage cost curve for the first 20-year analysis period under each of the three reduced capacity scenarios are displayed, along with the Reference Case curve in which no reduction of usable capacity was applied (i.e.,

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<sup>2</sup> Storage capacities were reduced to these levels for each individual storage basin and formation modeled in the analysis. No variation in the reductions based on geology, geography or other factors was applied at this.

the Reference Case curve represents a de facto 100% capacity case). Overall, the impact on the curves moving from 100% capacity to 50% and 10% are rather minor, with only a slight reduction in total annual CO<sub>2</sub> stored (as evidenced by the small leftward shifts in the far right end of the curves) to a more pronounced change at the low end of the curve where the available capacity in the most economically attractive EOR and ECBM options is progressively reduced and replaced by other higher cost storage capacity. Nonetheless, for the 100%, 50% and 10% capacity cases, there is at least 2,800 MtCO<sub>2</sub> per year that can be accessed for less than \$10/tCO<sub>2</sub> during the first 20-year period. It is not until the capacity is reduced to 1% of that available under the Reference Case that the matched annual capacity for China drops significantly, with just 23% as much CO<sub>2</sub> stored as in first time period of the Reference Case, and stranding an additional 2,260 MtCO<sub>2</sub>/yr.

The results from this first 20-year analysis period suggest that the CO<sub>2</sub> storage resource of China is in fact robust and able to provide sufficient matched capacity to China's large CO<sub>2</sub> sources, and at relatively stable costs, even if the ultimately accessible capacity is reduced by as much as 50%, or even 90%. However, should capacity estimates presented here overestimate achievable capacity by two orders of magnitude, leaving only 1% of the 2,300 GtCO<sub>2</sub> of estimated onshore storage capacity (or just 23 GtCO<sub>2</sub>), the potential for successful widespread CCS deployment in China becomes significantly more challenging, and in this scenario, CCS deployment would likely be limited to more selective or strategic applications.

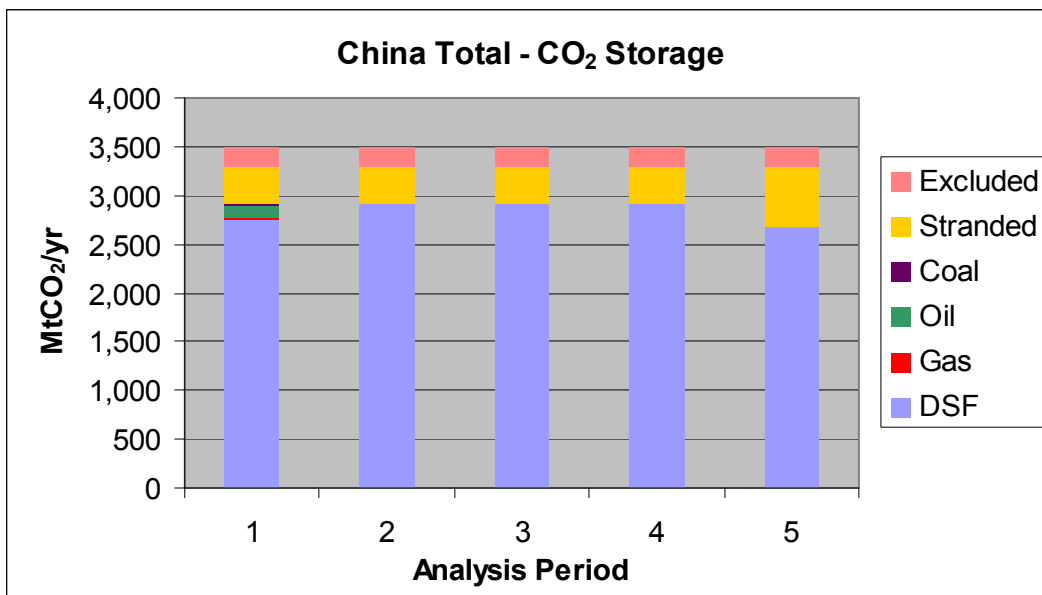


**Figure 5.10.** Cost Curves for Various Initial Capacities, First 20-year Analysis Period

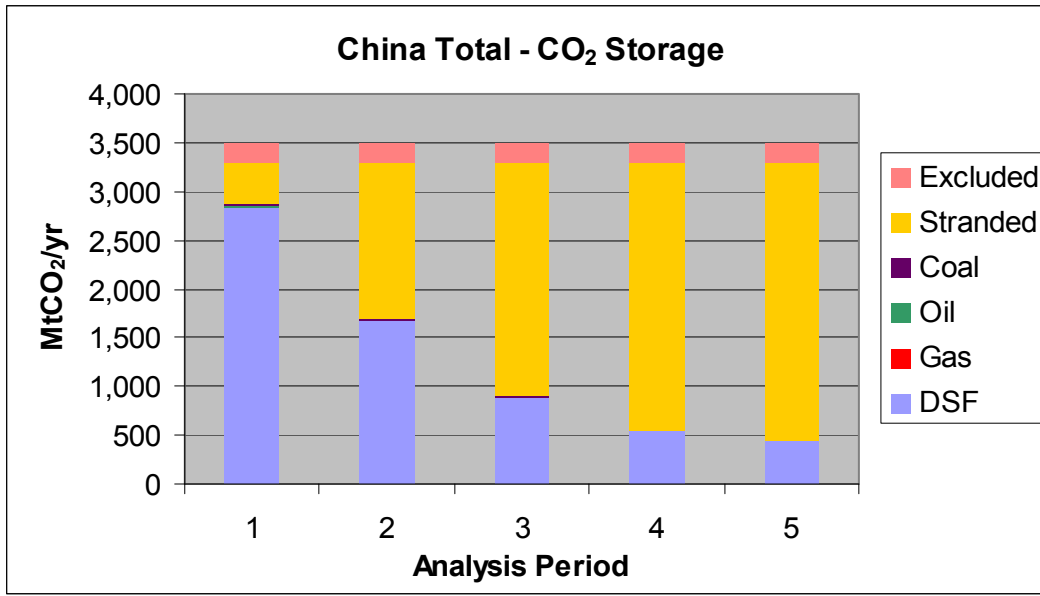
Examining the 50% capacity scenario more closely confirms that even if just half of the total estimated CO<sub>2</sub> storage capacity proves viable, CCS still provides a strong and likely cost effective climate mitigation option for China. The resulting disposition of the captured CO<sub>2</sub> over 100 years of full scale deployment, shown in Figure 5.11, suggests that even this level of available CO<sub>2</sub> storage capacity can provide for a stable, large-scale deployment of CCS in China over more than a century. Under this

reduced capacity scenario, the mass of stranded CO<sub>2</sub> grows only from 369 MtCO<sub>2</sub>/yr in this first 20-year time period (just 2% more than in the Reference Case), to 625 MtCO<sub>2</sub>/yr by the end of 100 years.

The prospect for long-term viability of large-scale CCS deployment becomes more questionable in the 10% capacity case. Under this scenario, in which the current estimate of storage capacity is reduced by a full 90%, the potential for significant CCS remains; however, it quickly diminishes as full-scale deployment progresses over time and storage reservoirs fill. Figure 5.12 shows the progression of CO<sub>2</sub> disposition over the modeled 100 years of full scale deployment, for this 10% capacity scenario. In this case, the fraction of CO<sub>2</sub> on supply each year that gets stored in a nearby geologic formation steadily decreases from 82% in the first analysis period, to 26% in the third, and 12% in the fifth 20-year period. The CO<sub>2</sub> that cannot find sufficient suitable storage capacity is then added to the stranded CO<sub>2</sub>, which grows significantly over time, to 2,860 MtCO<sub>2</sub>/yr by the end of the first 100 years modeled.



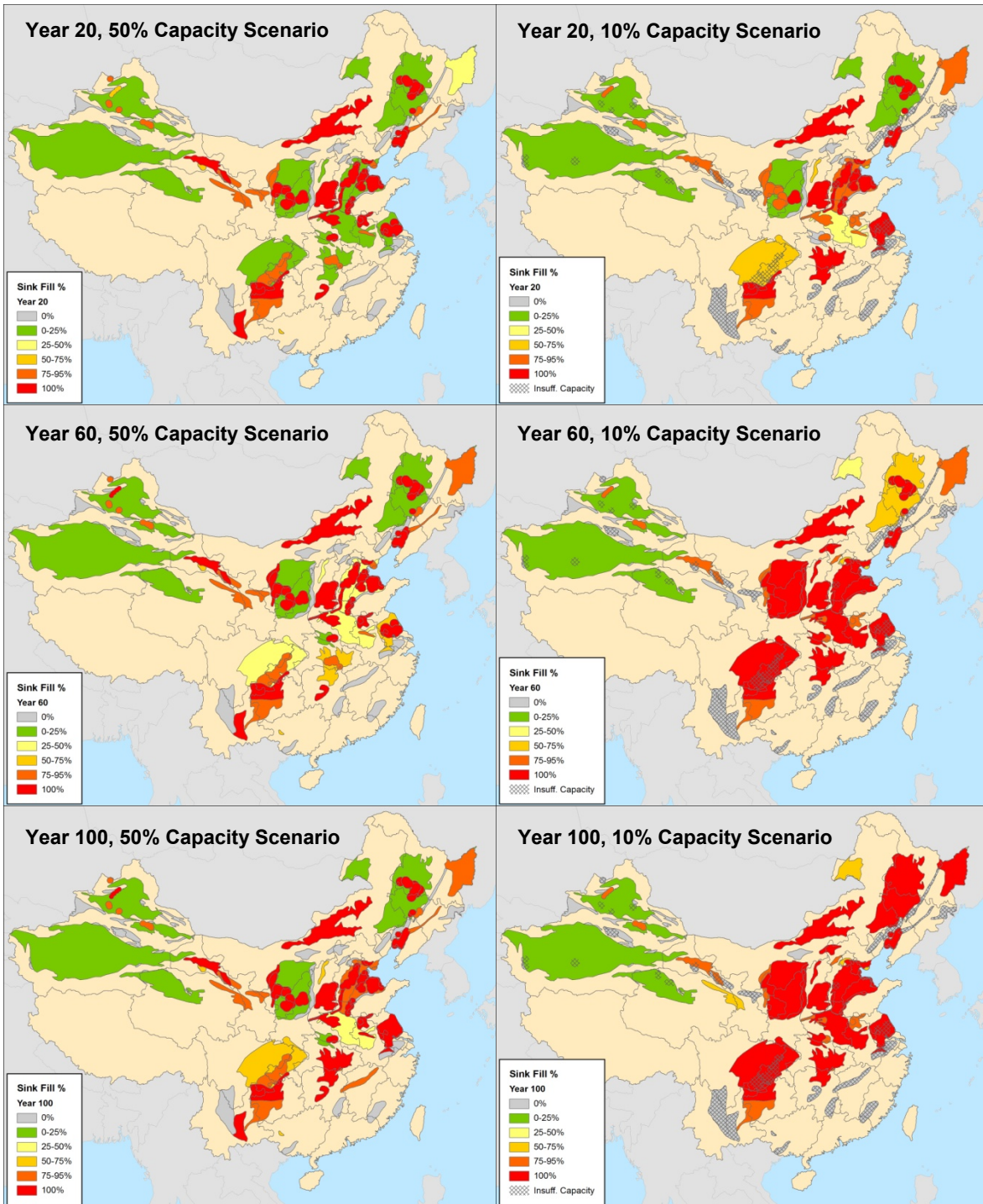
**Figure 5.11.** 100 Years of CO<sub>2</sub> Storage by Reservoir Class – 50% Capacity Case



**Figure 5.12.** 100 Years of CO<sub>2</sub> Storage by Reservoir Class – 10% Capacity Case

Overall results from this sensitivity analysis on available storage capacity suggest that even if the ultimately available or accessible storage capacity proves to be significantly less than the current capacity estimate, CCS appears able to provide a significant tool for addressing China’s CO<sub>2</sub> emissions while preserving the energy and economic security provided by China’s large, domestic industry and fossil fuel resources. Under most scenarios modeled, the costs for transporting, storing, and monitoring CO<sub>2</sub> for the majority of large CO<sub>2</sub> sources accessing storage remain within the \$2-8/tCO<sub>2</sub> range. Analyses in which only 50% of the estimated storage capacity is available suggest no major change in deployment potential over the course of more than 100 years of large-scale use. Even when 90% of the estimated storage capacity was modeled as unusable, results show that there is still more than adequate capacity for nearer term large-scale deployment, though more challenging to sustain over the longer term as reservoirs fill, particularly in areas with highly concentrated sources and emissions.

For more likely and moderate CCS deployment scenarios than were modeled here, there should prove to be adequate storage capacity in most places even under such significantly reduced capacities. These results, however, serve as a reminder that geologic storage capacity, no matter how large, is a finite resource and should be approached and managed carefully to maximize its benefit to society. Figure 5.13 shows the progressive filling of storage reservoirs in China over time for the 50% and 10% capacity cases. While the difference in available storage capacity is apparent at the end of the first 20 years of deployment, it becomes abundantly clear by the end of 60 and 100 years, by which time the storage capacity in most parts of the eastern half of China has been almost completely consumed under the 10% capacity scenario. Yet, even under this low capacity case, there are regions such the Northeast where the accessible capacity appears to be adequate over most of the century, and the Northwest where abundant unused capacity remains due to the low number of CO<sub>2</sub> sources that are within the allowable transport distance imposed by this study. This, combined with the potential for near offshore sub-sea storage capacity, suggest that the consideration of future facility siting or the evaluation of longer transport systems could provide additional access to CO<sub>2</sub> storage potential even under these highly constrained capacity conditions.



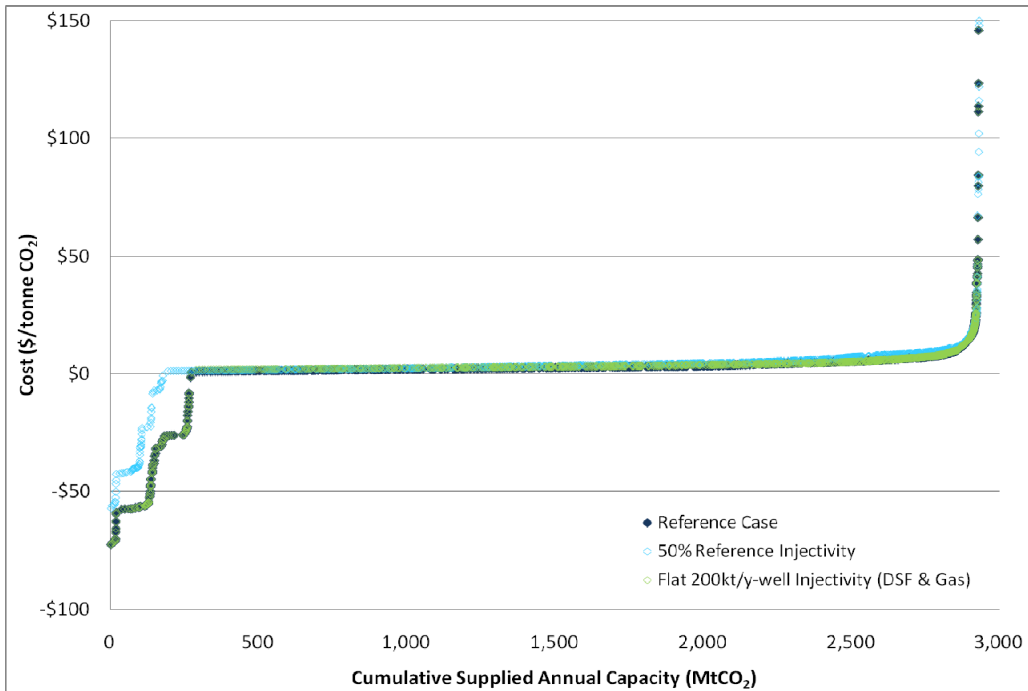
**Figure 5.13.** Mapping Reservoir Filling over 100 Years of Storage, for Years 20, 60, and 100: 50% Capacity Scenario (Left), 10% Capacity Scenario (Right)

## 5.4.2 Injection Rate Assumptions

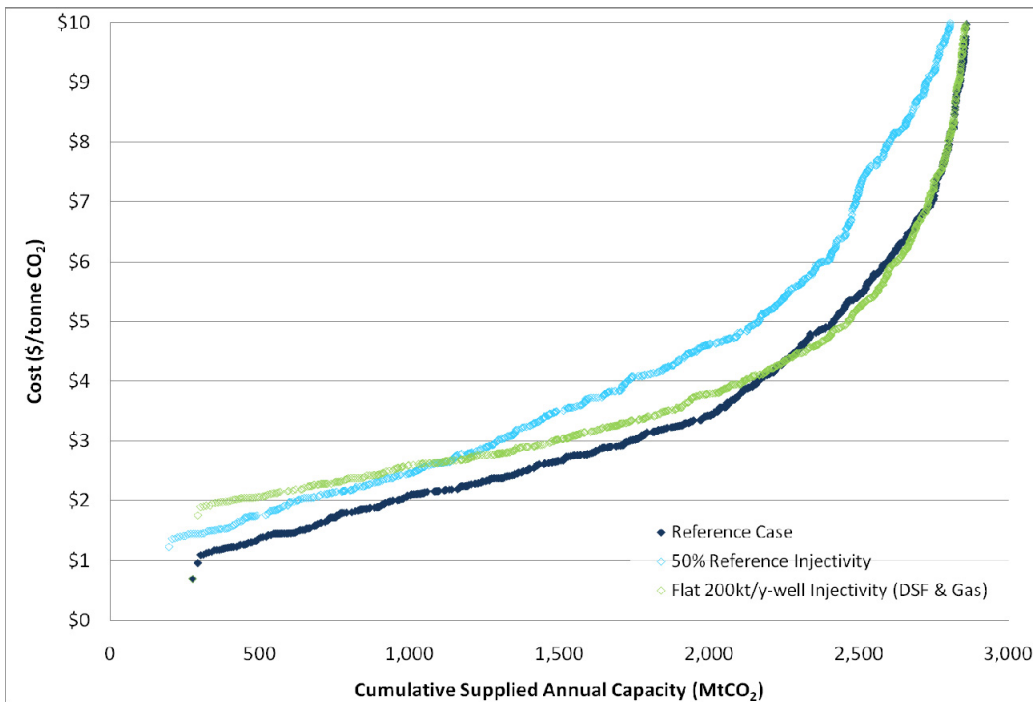
Because the rate at which CO<sub>2</sub> can be injected into a well directly impacts the number of wells required to inject a given CO<sub>2</sub> flow rate, as well as a project's footprint (impacting site characterization and CO<sub>2</sub> flowline costs), injection rate is a major cost driver for CO<sub>2</sub> storage. As discussed in Section 4.4.3, in the absence of actual field-tested injection rates for the storage formations analyzed, injection rates were estimated based on experience gained on projects in similar formation types. For deep saline formation and gas basins, an injection rate class was assigned according to available data and assumptions regarding thickness, porosity and permeability. The assumed injection rates applied to each formation class were derived from rates achieved at demonstration and commercial scale projects around the world, but because highly project-specific rates were applied at field and basin scales, it is important to understand the potential cost implications of overestimating these injection rates.

In order to examine the impact of injection rate on resulting costs, two separate sensitivity cases were evaluated. For the first case (light blue series, Figure 5.14), per-ton costs were calculated based on an across-the-board 50% cut in the injection rates assumed in the Reference Case. As this case shows, although costs are impacted across the entire set of source-sink pairs, decreased injection rates impact the value-added (EOR- and ECBM-based) storage projects at the lower end of the cost curve far more than storage opportunities in other project types, resulting in a nearly 30% reduction in the amount of negative-cost storage available. This disproportionate impact on value-added storage is the result of several factors. First, the assigned injection rates for EOR and ECBM projects are 21,000 and 14,000 tCO<sub>2</sub>/y per well respectively, five to seven times lower than the lowest rate for DSFs and gas basins. Thus, in the value-added formations where a project is already likely to be using its existing wells at or near their maximum assumed injection rate, a halving of injection rate is likely to result in a doubling of required injection wells, or nearly so, while projects in DSFs may be underutilizing their existing injection well(s) where CO<sub>2</sub> flow rate is significantly less than the maximum allowed injection rate. Second, under the assumptions of this analysis, EOR- and ECBM-based storage projects are required to bear the cost of production infrastructure for oil and gas recovery (see Section 4.4.4). In particular, the number of required production wells for costing purposes is estimated here as a function of injection wells, and because more than one production well is required per injection well, this results in an amplification of the impacts associated with decreased injection rate per injection well.

Though not as apparent, costs are also impacted on the positive cost portion of the cost curve. Decreased injection rates in non-value-added reservoirs result in increased costs due to requiring additional wells; and the larger resulting project areas increase costs associated with site characterization and CO<sub>2</sub> flowlines. For projects whose costs are dominated by these storage related components, it is not surprising to see a significant increase in total costs. This is most evident in the selective view of the sensitivity curves shown in Figure 5.15, which focuses just on the portion of the curve between \$0 and \$10/tCO<sub>2</sub>. Projects at the low end of this curve exhibit close to a 50% increase in net costs, as low transport costs make storage-related expenses a more significant cost component for these source-reservoir pairs. Higher up the curve, as transport distances and costs increase, the net impact of the 50% reduction in injection rates results in a more modest increase in total cost, yet a larger change in absolute cost, given the higher starting points. For example, at approximately 2,600 MtCO<sub>2</sub> (where the Reference Case total cost is about \$6/tCO<sub>2</sub>) the 50% decrease in injection rates drives net cost up 33%, or \$2/tCO<sub>2</sub>, while at the lower end a 50% increase in net cost corresponds to a \$0.50/tCO<sub>2</sub> rise. Additionally, the cost optimizing nature of the source-reservoir matching procedure tends to keep the resulting cost increases within a more moderate range as the costs increase.



**Figure 5.14.** Injection Rate Sensitivity Cases, Contrasted With the Reference Case Curve



**Figure 5.15.** Injection Rate Sensitivity Cases, Zoomed in View of \$0-10/tCO<sub>2</sub> Range



The second injection rate sensitivity focuses solely on altering the assumed rates for DSFs and gas basins, rather than reducing injection rates across all formation types. In this case, the *Low* (100,000 tCO<sub>2</sub>/y), *Moderate* (200,000 tCO<sub>2</sub>/y), *High* (400,000 tCO<sub>2</sub>/y) and *Very High* (800,000 tCO<sub>2</sub>/y) injection rates assigned within the Reference Case were collapsed to a single injection rate of 200,000 tCO<sub>2</sub>/y, corresponding to the *Moderate* injection rate class. The cost curve resulting from this sensitivity is represented by the green series on Figure 5.14, and at the scale shown, is nearly indistinguishable from the Reference Case curve. However, as Figure 5.15 shows, when magnifying the area of the curve between \$0-10/tCO<sub>2</sub>, some interesting relationships can be seen. In particular, at the lower end of this cost range, the roughly \$1/tCO<sub>2</sub> increase in transport and storage costs is significant, but this cost increase disappears around \$4.30/tCO<sub>2</sub> and the sensitivity case actually results in a small cost savings over the Reference Case briefly before the two curves again converge. Because the lowest-cost DSF projects in the Reference Case tend to be those with the highest per-well injection rate and also the largest CO<sub>2</sub> flow rate, these projects see the most significant cost increase because often their injection rates are dropping by a factor of 2 or 4. For other projects (including many of those for whom the sensitivity cost is actually cheaper than the Reference Case), this sensitivity case revised their injection rates upward – doubling from 100,000 to 200,000 tCO<sub>2</sub>/y. This sensitivity analysis demonstrates the value of using differentiated injection rates where data are available to realistically apply such an assumption.

These sensitivity analyses were developed in order to understand how overestimating injection rates would impact the cost curves presented in this report. While injection rates are critical to understand for an actual project and can have a significant impact on capital costs and economic viability, it is interesting to note that, even if the injection rates presented here overestimate achievable rates by 100%, the overall cost impacts and implications for the deployment potential of CCS technologies in China overall are relatively small. In the case of a consistent reduction to all injection rates, the largest percentage cost impacts are seen at the lower end of the cost curve, populated by source-reservoir pairs exhibiting the lowest transport costs. However, this is also where the largest impact is seen when the Moderate injection rate class is applied to all DSFs and gas basins, as these pairs experience the most significant drop in assumed injection rate. It is also clear that, where the data exist to support differentiation of injection rate assumptions – and resulting storage costs – this type of assumption leads to more nuanced cost curves that more fully present the impact of formation characteristics on total per-ton storage costs.



## 6.0 Conclusions

This study represents the first of its kind assessment of the CO<sub>2</sub> storage options and costs for regions across the People's Republic of China. The ultimate role of CCS technologies in global efforts to cost effectively reduce greenhouse gas emissions will be determined by a combination of the stringency and timing of future greenhouse gas emissions reduction policies, the full costs of employing end-to-end CCS systems, and how those costs compare to other methods of bringing about large scale decarbonization of the economy. It is therefore essential to understand the costs of deploying CCS relative to other emissions mitigation technologies and this work begins to highlight the potential for CCS technologies to deploy in China. This first-order evaluation provides the most comprehensive look to date at the potential for CCS technologies to deploy across multiple industrial sectors, regions, and geology that might be amenable to secure long-term storage of CO<sub>2</sub>. Given the very emerging nature of this area of research, a number of assumptions were applied; while selected to be generally conservative in nature, they can easily be updated as additional knowledge and data are compiled.

Results of this first-order assessment indicate that there may be as much as 2,300 gigatons of potential CO<sub>2</sub> storage capacity in onshore Chinese basins, significantly more than previous estimates have suggested. The vast majority of this capacity appears to be in deep saline sedimentary formations that are distributed broadly across many regions of China. This study identified 1,623 large stationary CO<sub>2</sub> point sources in China that each emit at least 100,000 tCO<sub>2</sub> per year and whose cumulative emissions total more than 3,890 MtCO<sub>2</sub> released to the atmosphere annually. Many (91%) of the nation's 1,623 modeled large CO<sub>2</sub> point sources have access to one or more candidate storage reservoirs within 160 km (100 miles). Over half may have a candidate storage formation directly beneath them or within a very short distance. In the North, Northwest, and Southwest regions, candidate storage formations are particularly well-positioned to be accessed by CO<sub>2</sub> sources, with over 90% of the sources having at least one potential storage option within just 80 km (50 miles).

Economic analysis indicates that the costs for CO<sub>2</sub> transport and storage in China can vary significantly based upon the combined characteristics of the CO<sub>2</sub> source and target storage reservoir. Results suggest that there may be significant potential for storage in value-added reservoirs that offer the potential to recover incremental oil or coalbed methane. Such recovery via EOR or ECBM may offer significant incentive for pursuing CO<sub>2</sub> storage activity in the nearer term, as the resulting revenues can help to offset costs. Cost curve modeling suggests that significant low-cost CO<sub>2</sub> storage may be available in China, though examination across multiple analysis periods shows that this resource is likely to be filled quickly. Therefore, issues regarding the timing of availability for these potential targets, as well as the expected duration of success should be further evaluated and incorporated into future modeling efforts to gain better insights into the true potential for these low-cost early opportunities.

The bulk of the potential available CO<sub>2</sub> storage capacity in China exists in deep saline-filled sedimentary formations (DSFs). The cost curve analysis presented here suggests that the majority of emissions from China's large CO<sub>2</sub> point sources can be stored in these DSFs, at estimated costs of less than \$10/tCO<sub>2</sub>. In fact, nearly 90% of the CO<sub>2</sub> stored in this analysis – from sources that were able to locate an available storage target – utilizes one of these DSFs. Regional cost curves, while similar in overall trends to the aggregate curve, highlight some of the unique characteristics of CO<sub>2</sub> source density and potential storage availability amongst the six administrative regions in China.

An important finding of this study is that the heavily developed coastal areas of the East and South Central regions appear to have less access to large quantities of onshore storage capacity than many of the inland regions. In fact, in the analysis, many sources in these coastal regions are unable to access suitable CO<sub>2</sub> storage capacity within the 240 km (150 mile) search radius. Storage options do appear to be present in nearby offshore sub-sea basins which would likely offer lower overall costs compared to storage in more distant onshore basins. However, the economic examination of these offshore basins was outside the scope of this present study. Future work will need to examine the economics associated with utilizing this offshore storage capacity to provide needed emission mitigation options for industry and power sources in this region.

Though in-depth field and laboratory studies will be needed to validate current capacity estimates and regional accessibility of storage potential, results of this study indicate that China has a robust and broadly distributed geologic CO<sub>2</sub> storage resource and that the costs of transport and storage for most projects should fall within a range of \$2-8/tCO<sub>2</sub> over many decades of large-scale deployment. Sensitivity analyses indicate that this cost range holds true even if there proves to be only half as much useable storage capacity as projected. Cases in which only 50%, 10% and 1% of the identified 2,300 GtCO<sub>2</sub> storage capacity are available for use were analyzed and only in the most pessimistic and unlikely of these scenarios do significant constraints develop on the cost effective deployment of CCS in China. For all but the very lowest capacity scenario examined (only 23 GtCO<sub>2</sub> of 2,300 GtCO<sub>2</sub> available), CCS appears able to play a significant role in addressing China's CO<sub>2</sub> emissions while at the same time preserving the energy and economic security provided by China's large, domestic industry and fossil fuel resources.

There are numerous additional areas for future research on the potential for CCS technologies to deploy within China. Some of these include an ongoing effort to update CO<sub>2</sub> source data for both existing and emerging industries and estimating potential impacts on continued growth patterns. Continued development of core geologic data and greater understanding of basin and sub-basin scale geology as it pertains to the capacity, injectivity, suitability, timing of availability and economics of CO<sub>2</sub> injection and storage will be important, as it continues to be in all regions of the world where CCS is being studied.

The analysis presented here intentionally omits the cost of CO<sub>2</sub> capture, compression and dehydration in order to focus on the storage side of CCS; future analyses will incorporate these significant additional cost components to provide a more complete picture of estimated end-to-end CCS system costs. While the model used in this study has been significantly updated, better understanding and improved modeling of component costs, specific Chinese market conditions, and other factors impacting costs of deployment in China will also be considered in greater detail in future work. The present study and planned follow-on research will be critical to defining global climate- and energy-related policy agendas, understanding opportunities and potential challenges for deploying CCS in China, and identifying and coordinating potential pilot projects to pave the way for commercial-scale deployment of this class of technologies.

Finally, much of the discussion about China's options for addressing climate change have focused to date almost exclusively on coal – the nation's large indigenous reserves, and its heavy and increasing use in powering China's fast-growing economy. This discussion of China's reliance on coal coupled with the need to reduce global greenhouse gas emissions is too often framed as an all-or-nothing proposition which has created a false dichotomy suggesting that China must choose between either continuing to use domestic coal and bearing the environmental consequences, or forgoing cheap domestic reserves and bearing the economic consequences. This study demonstrates for the first time the significant potential

for carbon dioxide capture and storage technologies to deploy in China, presenting the possibility of a third option that supports continued economic growth with coal while safely and securely reducing CO<sub>2</sub> emissions to the atmosphere. CCS technologies are essential to the development of near-zero emission coal technology, and may help China preserve the economic and societal benefits of continuing to utilize its vast domestic coal resource, even in a carbon-constrained world. Additional research is needed, and many areas for follow-on evaluation are proposed based on this initial study. However, the results of this analysis clearly suggest that CCS may be able to deploy broadly within China and provide significant value within a large and diverse portfolio of advanced energy technology and strategic measures focused on global climate change mitigation.



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