West Coast Regional Carbon Sequestration Partnership
CO_2 Sequestration GIS Analysis

Topical Report

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Principal Author:
Howard J. Herzog

September 30, 2005

DOE Contract No.: DE-FC26-03NT41984

Submitted by:
Larry Myer
PIER Program
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Prepared by:
Howard Herzog
Massachusetts Institute of Technology
Laboratory for Energy and the Environment
77 Massachusetts Avenue, Room E40-455
Cambridge, MA 02139-4307

United States Government Disclaimer

California Energy Commission Disclaimer

Abstract

This report presents the Geographic Information System (GIS) analysis part of the Phase I study of the West Coast Regional Carbon Sequestration Partnership (WESTCARB). In this report, GIS software and other tools were used to characterize the WESTCARB region and assess its carbon sequestration potential. The WESTCARB member states include Alaska, Arizona, California, Nevada, Oregon, and Washington.

In this report, we present:

- A summary of stationary carbon dioxide (CO_2) sources and the levels of emissions within the WESTCARB region,
- A first-order scoping analysis to determine the maximum CO_2 storage capacity of the carbon sinks within the WESTCARB region (except for Alaska),
- Methods for determining the CO_2 capture costs from the types of CO_2 sources included in the study,
- A methodology for estimating the requirements and costs of transporting CO_2 from the sources to the storage reservoirs,
- An initial matching between CO_2 sources and sinks in the WESTCARB region (except for Alaska) based on minimum straight-line distance, and
- A detailed source-sink matching analysis that is used to develop CO_2 sequestration marginal abatement cost curves. This analysis is restricted to California due to the limited availability of more expansive datasets. This type of analysis will be expanded to the entire WESTCARB region in Phase II.

It must be emphasized that this is only an initial analysis. It was based on the best information available during Phase I of the regional partnerships. This effort will be continued and improved in Phase II using more sophisticated tools and more detailed data sets.

Table of Contents

List of Figures

List of Tables

1 Executive Summary

This report presents the Geographic Information System (GIS) analysis part for the Phase I study of the West Coast Regional Carbon Sequestration Partnership (WESTCARB) in characterizing the CO_2 sequestration potential for the region. The following three components of carbon dioxide (CO_2) sequestration are evaluated in the study:

1. CO_2 source analysis,
2. CO_2 storage capacity estimation, and
3. CO_2 source-sink matching and sequestration cost.

As a first step, the study analyzed the information regarding the stationary CO_2 sources in the WESTCARB region. The data was compiled and stored as a database in the WESTCARB GIS server. The database includes information for 77 facilities from four categories with total annual CO_2 emissions of 159 million metric tonnes (Mt). Table ES-1 summarizes the CO_2 emissions from major stationary sources in the WESTCARB region by facility type and by state, respectively. The CO_2 emissions from power plants are actual 2000 CO_2 emissions from the eGRID database. Annual CO_2 emissions from cement plants and refineries are estimates based on production capacities. While the production capacities for gas processing facilities are all missing from the database, no CO_2 emissions are estimated for these facilities. Power plants are the single largest source of CO_2 emissions, accounting for more than 80 percent of the emissions from the stationary sources in the database. California has the highest annual CO_2 emissions in the region, representing over one-third of the regional total emissions, followed closely by Arizona.

Table ES-1. CO_2 emissions from stationary sources by facility type and state

	Power Plants		Cement		Gas Processing[d]		Refineries		Total	
State	**# of Facilities**	**CO_2 Emiss (Mt)**	**# of Facilities**	**CO_2 Emiss (Mt)**	**# of Facilities**	**CO_2 Emiss (Mt)**	**# of Facilities**	**CO_2 Emiss (Mt)**	**# of Facilities**	**CO_2 Emiss (Mt)**
AK	6	2.3	0	0.0	3	0	3	2.6	12	4.9
AZ	7	48.3	2	1.4	0	0	0	0.0	9	49.7
CA	18	36.5	6	6.0	2	0	7	11.3	33	53.8
NV	6	24.8	3[a]	0.0	0	0	0	0.0	9	24.8
OR	3	7.4	2[b]	0.6	0	0	0	0.0	5	8.0
WA	3	12.1	3[c]	0.8	0	0	3	4.4	9	17.3
Total	**29**	**131.3**	**16**	**8.8**	**5**	**0**	**13**	**18.4**	**77**	**158.5**

[a]The WESTCARB database contains no production capacity data for cement in Nevada.
[b]Only one cement plant in Oregon has production data.
[c]Only two cement plants in Washington have production data.
[d]No production capacity data or CO_2 emission data is available for gas processing facilites.

The WESTCARB database contains two types of potential geological storage sinks for CO_2 sequestration: hydrocarbon (oil & gas) reservoirs and saline aquifers. For hydrocarbon reservoirs, the storage capacity estimation methods in the JOULE II report (Holloway *et al.*, 1996) were adapted as the baseline model in estimating the CO_2 storage capacity. The baseline model was modified to accommodate the data deficiency problem in the database. The modified models were then applied to estimate the CO_2 storage capacity for each candidate hydrocarbon CO_2 sink based on the currently available information. However, the information for saline aquifers in the WESTCARB database is not complete enough to estimate the CO_2 storage capacity of these aquifers. Therefore, only the theoretical models for calculating the CO_2 storage capacity of saline aquifers were presented for future reference and no such capacities were actually calculated for candidate aquifer sinks.

After identifying the CO_2 sources and candidate sinks, the study then evaluated the CO_2 sequestration potential in the WESTCARB region by analyzing the matching between sources and sinks. Figure ES-1[1] shows the distribution of CO_2 sources and sinks that were considered in the source-sink matching analysis. After limiting to CO_2 sources in the contiguous-U.S. part of the WESTCARB region and excluding sources without CO_2 emission data, a total of 58 CO_2 sources were studied in the source-sink matching analysis. These 58 CO_2 sources include 10 coal-fired power plants, 27 gas-fired power plants, 11 cement plants and 10 refineries, with an annual amount of 184 Mt CO_2 to be sequestered[2].

As a preliminary analysis, the study performed a straight-line distance-based matching for the entire contiguous-U.S. part of the WESTCARB region, connecting each source to its closest sink in terms of straight-line distance. In this preliminary exercise, neither the optimal pipeline path nor the sink's storage capacity constraints were considered. The straight-line distance matching analysis was performed for each of the three different groups of eligible sinks and a combination of them altogether (see Tables ES-2 and ES-3). Given that the WESTCARB server lacked sufficient data to evaluate the CO_2 sequestration potential for Nevada, the matching exercises were performed under two scenarios: with and without Nevada saline aquifers. Table ES-2 and Table ES-3 summarize the matching results under the two scenarios in terms of annual CO_2 storage capacity by marginal straight-line distance. If enhanced oil recovery (EOR) sites were the only sinks used for sequestration, about one-third of the CO_2 sources (by volume) could be matched with a sink that is less than 50 km (31 mi) away while about one half of the sources could be matched with a sink that is less than 250 km (155 mi) away. If all sink types, including Nevada sinks, were considered for sequestration, however, more than four-fifths of CO_2 sources could be matched with appropriate sinks within 50 km (31 mi). However, there are still some sources that cannot be matched to any sinks that is within 250 km (155 mi) from the sources.

[1] All the maps presented in this report include all WESTCARB member states except Alaska.

[2] The annual amount of CO_2 to be sequestered differs to the 159 Mt annual emissions reported previously. The 184 Mt $CO_2$was estimated under the following three assumptions: (1) an 80% operation capacity for power plants; (2) full production capacity for non-power stationary CO_2 sources; and (3) a capture efficiency of 90% for all sources.

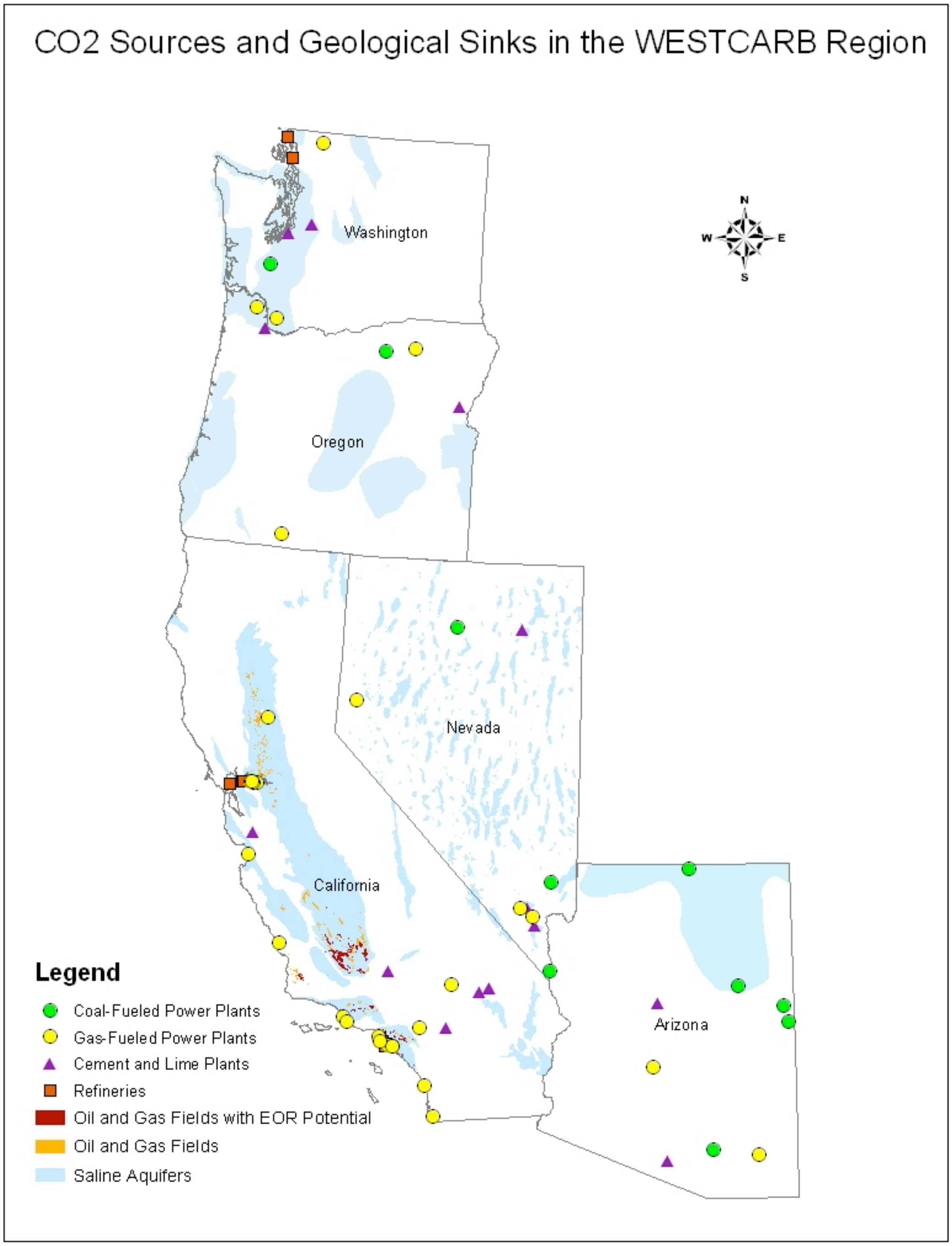


Figure ES-1. CO_2 sources and sinks in the WESTCARB region

Table ES-2. CO_2 storage capacity (Mt/yr) by marginal straight-line distance to nearest sink; Nevada aquifers included

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in WC Region	154	174	176
All Sinks	154	174	176

Note: The CO_2 storage rate was 184 Mt/yr.

Table ES-3. CO_2 storage rate (Mt/yr) by marginal straight-line distance to nearest sinks; Nevada aquifers excluded

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in WC Region Excluding Navada	139	168	176
All Sinks	139	168	176

Note: The CO_2 storage rate was 184 Mt/yr.

This study further presented a GIS-based method of matching sources and sinks considering the optimal pipeline route selection and sink's capacity constraint. The pipeline construction costs vary considerably according to local terrains, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks. In order to account for such obstacles, the locations and characteristics of these obstacles were loaded into the spatial database and were used to construct a single aggregate transportation obstacle layer. In contrast to the distance-based matching analysis, this least-cost matching analysis links each CO_2 source to a least-cost geological sink based on the sum of the transportation costs associated with the least-cost path and the injection cost subject to the sink's capacity constraint. An iterative algorithm was used to approximate an optimal system solution. Due to the limited availability of detailed sink data for the WESTCARB region, this least-cost matching analysis was only performed for California where the sink data set is relatively rich.

The least-cost source-sink matching analysis for California was conducted in two stages. In the first stage, only 35 EOR sites with storage capacity over 20 Mt[3] were included as candidate sinks, which results in an overall storage capacity of 3.2 giga metric tonnes (Gt). The amount of CO_2 that needs to be sequestered from the 31 CO_2 sources in California over 25 years was estimated

[3] Most of the CO_2 sources will emit more than 20 Mt CO_2 over the 25-year project lifetime.

to be 2.1 Gt. The cost calculation assumed a credit of \$16/metric tonne (t) CO_2 for EOR injection and omitted the injection cost. With the assumption of a constant CO_2 credit, the optimization algorithm only considers minimizing the overall transportation of the network system. Figure ES-2 shows the marginal per-tonne CO_2 transportation cost by annual CO_2 storage rate in oil fields with EOR potential. As the CO_2 storage capacity in the EOR sinks was larger than the 25-year CO_2 flow, all the sources were connected to their corresponding least-cost EOR sinks. The transportation costs for most of the sources are below \$10/t CO_2 except for a few outliers.

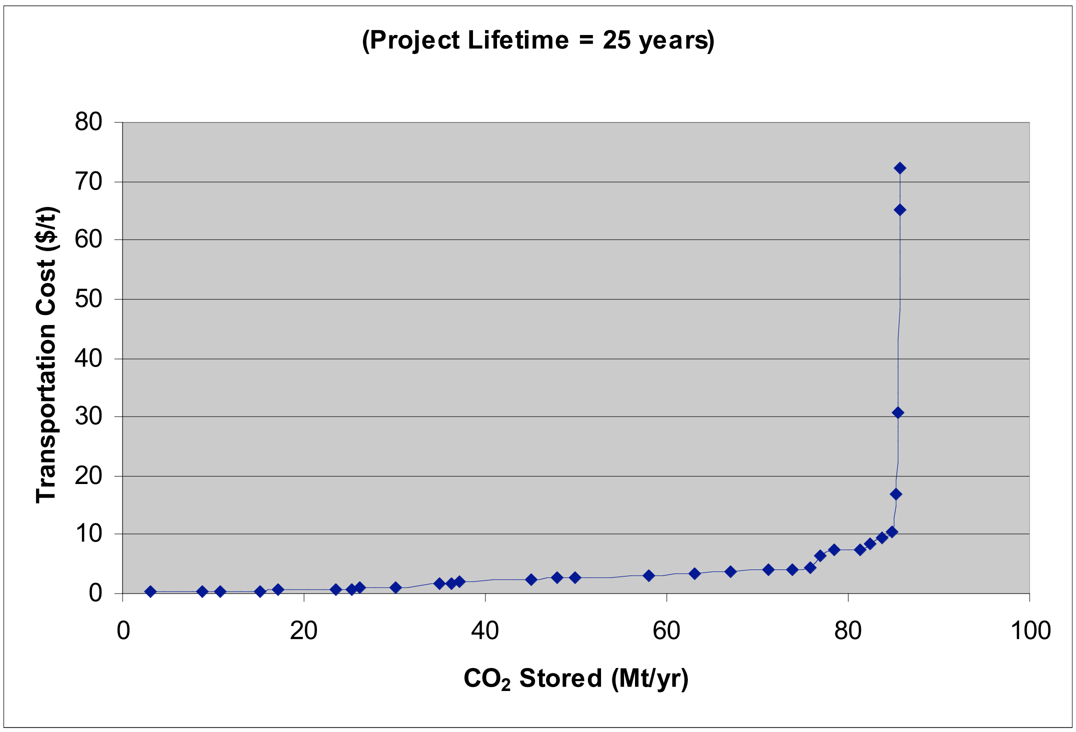


Figure ES-2. Marginal transportation cost by annual CO_2 storage rate in oil fields with EOR potential, California

Only four sources had transportation costs to the closest EOR site greater than the credit value of \$16/t CO_2. For the second stage of least-cost source-sink matching analysis for California, a new round of source-sink matching was applied to these four sources with the same algorithm as before, but using the oil and gas fields without EOR potential and saline aquifers suitable for CO_2 storage in California as the sink layer instead. A final check was run to conduct a full-cost comparison to decide whether they should be matched to EOR or non-EOR sinks. Except for the source with transportation to EOR site of \$16.8/t CO_2 that remained to be connected to its EOR destination, the other three sources were reassigned to saline aquifers instead because of the lower full costs.

Figure ES-3 shows the marginal full sequestration cost by annual CO_2 storage rate. For sources matched with EOR sites, the full cost estimate included costs for capture and transportation, net of an EOR credit. For sources matched with non-EOR hydrocarbon fields or aquifers, the full cost estimate included costs for capture, transportation, and injection. The results of the full cost sequestration analysis in California indicate that 20, 40, or 80 Mt of CO_2 per year could be sequestered in California at a cost of \$31/t, \$35/t, or \$50/t, respectively.

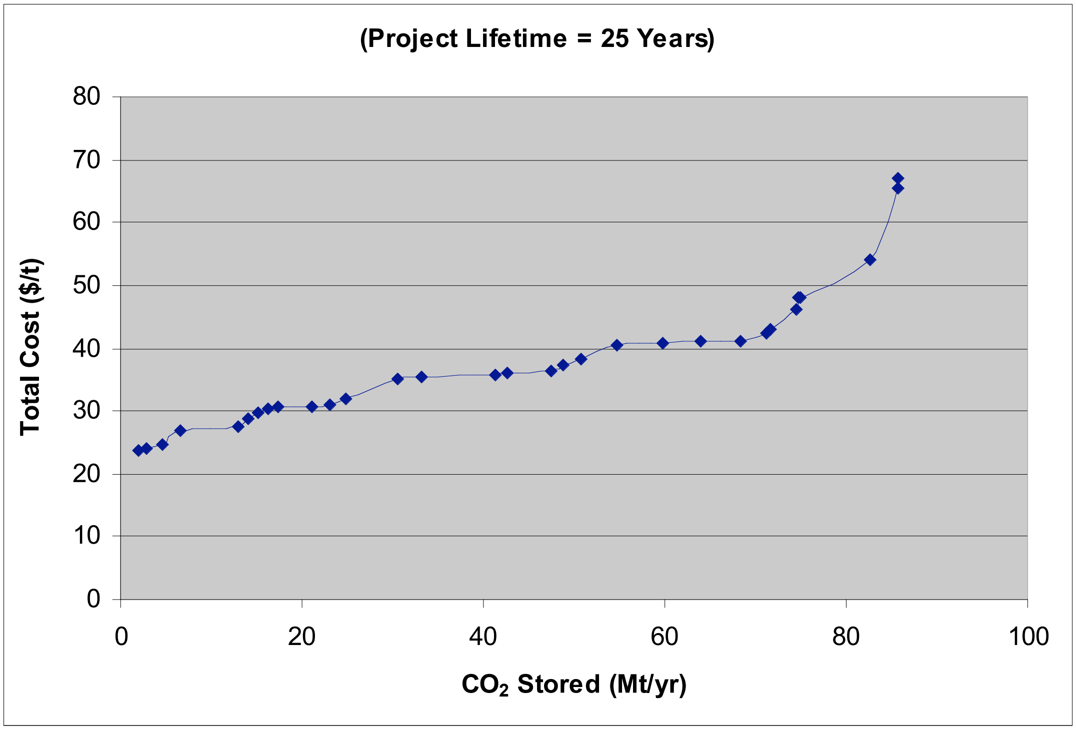


Figure ES-3. Marginal total cost by annual CO_2 storage rate, California

2 Experimental

This project involves computer modeling and there is no laboratory work associated with this project.

3 Results and Discussions

3.1 Stationary CO_2 Sources in the WESTCARB Region

This report summarizes the CO_2 source database contained in the WESTCARB database. The database contains the location and capacities of the major stationary sources of CO_2 in the WESTCARB study area.

The database contains the following four major types of stationary sources:

- Power plants,

- Cement plants,
- Gas processing facilities, and
- Refineries.

3.1.1 Fossil-Fuel Power Plants

The WESTCARB database used for analysis contains information regarding fossil-fuel power plants in the member states for the year 2000. The database contains information about each facility including location, ownership, generating capacity, fuel type, annual electricity production, and annual emissions. The capacity and CO_2 emissions data are from the eGRID database and are for the year 2000. Table 1 summarizes the fossil-fuel power plants in the WESTCARB region by state. In the database, Alaska is the only state in the WESTCARB region with oil-fired power production facilities. Figure 1 plotted these fossil power plants in the contiguous-U.S. part of the WESTCARB region by type, location, and annual CO_2 emissions. As can be seen in the map, all the power generation facilities in California power in the database are gas-fired.

Table 1. Power generation capacity and CO_2 emissions by fuel and state (2000)

	Gas			Oil			Coal		
State	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)
AK	2	684	1,686	3	193	342	1	28	261
AZ	2	1,173	4,931	0	0	0	5	5,745	43,394
CA	18	17,973	36,450	0	0	0	0	0	0
NV	3	1,835	4,575	0	0	0	3	2,769	20,191
OR	2	1,207	3,400	0	0	0	1	560	3,999
WA	2	494	1,758	0	0	0	1	1,460	10,345
Total	**29**	**23,366**	**52,800**	**3**	**193**	**342**	**11**	**10,562**	**78,189**

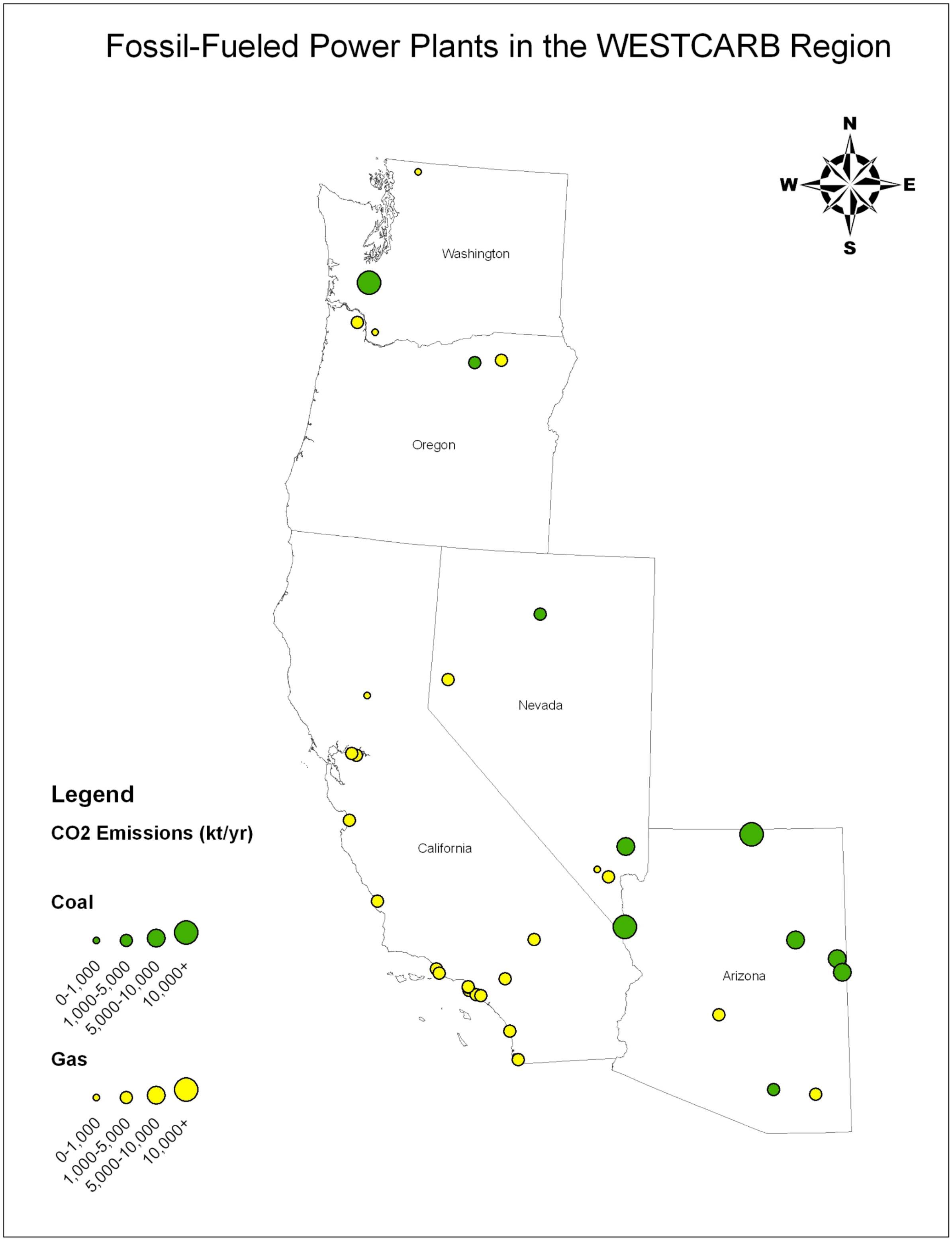


Figure 1. Fossil-fueled power plants in the WESTCARB region

3.1.2 Non-Power Stationary CO_2 Sources

The WESTCARB database contains three major non-power stationary CO_2 sources: cement plants, gas processing facilities, and refineries. Figure 2 shows the geographical distribution of these non-power stationary CO_2. This section briefly summarizes each type of these non-power stationary CO_2 sources in the database.

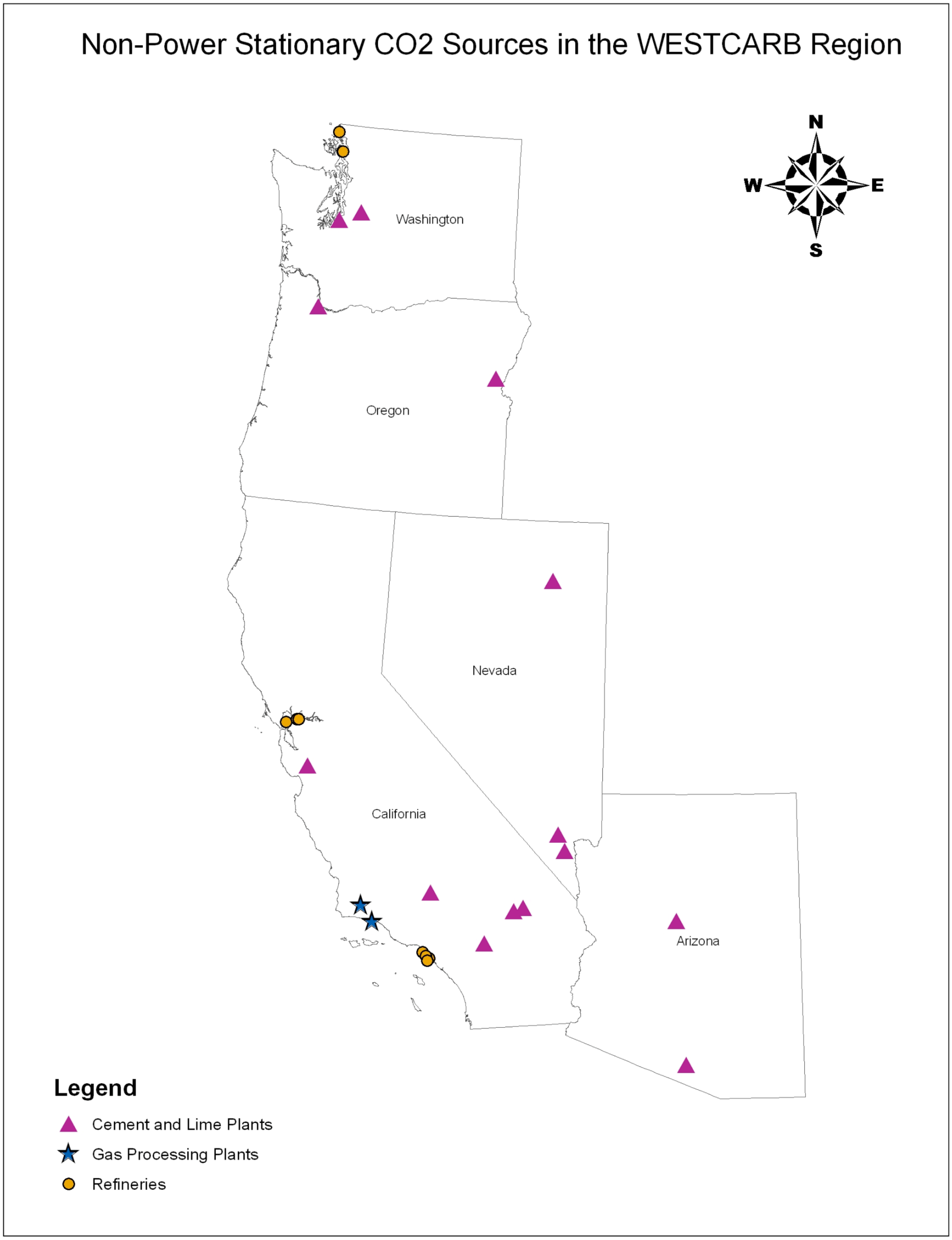


Figure 2. Non-power CO_2 Sources in WESTCARB region

3.1.2.1 Cement Plants

Table 2 summarizes the data for cement plants in the WESTCARB database by state. The database contains information for 16 facilities. California has the most production facilities with 6,650 kt of annual cement production capacity with total estimated emissions of 6,016 kt of CO_2.

Table 2. Cement and lime plant capacity and estimated CO_2 emissions by state

State	Number	Capacity (kt/yr)	Estimated CO_2 Emissions(kt/yr)
AK	0	0	0
AZ	2	1,574	1,424
CA	6	6,650	6,016
NV	3[a]	0	0
OR	2[b]	660	597
WA	3[c]	855	774
Total	**5**	**9,739**	**8,811**

[a]The WESTCARB database contains no production capacity data for cement in Nevada.
[b]Only one cement plant in Oregon has production data.
[c]Only two cement plants in Washington have production data.

3.1.2.2 Gas Processing Facilities

Table 3 summarizes the data for gas processing facilities in the WESTCARB database by state. To date, the WESTCARB database only contains five gas-processing facilities in two states. But even for these facilities, no data on production capacity or CO_2 emissions is available.

Table 3. Gas processing capacity and estimated CO_2 emissions by state

State	Number	Capacity (MMCFD)[a]	Estimated CO_2 Emissions (kt/yr)[a]
AK	3	0	0
AZ	0	0	0
CA	2	0	0
NV	0	0	0
OR	0	0	0
WA	0	0	0
Total	**5**	**0**	**0**

[a] No production capacity data or CO_2 emission data is available in in the WESTCARB database.

3.1.2.3 Refineries

Table 4 summarizes the data for refineries in the WESTCARB database by state. The database also lists refineries for Alaska, California, and Washington, with California having the largest share of production capacity and CO_2 emissions in refineries.

Table 4. Refinery capacity and estimated CO_2 emissions by state

State	Number	Capacity (1000 barrels / stream day)	Estimated CO_2 Emissions (kt/yr)
AK	3	317	2,642
AZ	0	0	0
CA	7	1,356	11,312
OR	0	0	0
NV	0	0	0
WA	3	485	4,046
Total	**13**	**2,158**	**18,000**

3.2 WESTCARB CO_2 Storage Capacity Analysis

This section presents the theoretical principles supporting the baseline estimation of CO_2 storage capacity in the WESTCARB region. Methods were developed to estimate the CO_2 storage capacity of three different types of geological sinks:

- Hydrocarbon (oil & gas) reservoirs,
- Saline aquifers, and
- Coalbeds.

These methods were integrated into software tools for use with ArcGIS modeling software. These standardized capacity tools were then used with the collected WESTCARB data to estimate the CO_2 storage capacity of the geological sinks in the study region. Due to data availability, this Phase I study only evaluates the CO_2 storage capacity in hydrocarbon reservoirs in the state of California. It will be extended to saline aquifers and coalbeds in Phase II when more detailed data sets are available.

The storage capacity estimation methods in the JOULE II report (Holloway *et al.*, 1996) were adapted as the baseline models in estimating the CO_2 storage capacity for hydrocarbon reservoirs and saline aquifers, while the methodology developed by Reeves (2003) was used as the baseline model in estimating the CO_2 storage capacity for coalbeds. These baseline models were modified to accommodate the availability of information.

3.2.1 CO_2 Storage in Hydrocarbon Reservoirs

3.2.1.1 CO_2 Storage Capacity of Hydrocarbon Reservoirs

A significant amount of pore space is vacated in underground hydrocarbon reservoirs when hydrocarbons are produced from the reservoir. CO_2 can be stored in the pore space left vacant by the hydrocarbon production. The CO_2 storage capacity of each reservoir depends on the amount of hydrocarbon fuel produced from the reservoir, with the total expected future storage capacity dependant on the total expected hydrocarbon production. In order to estimate storage capacity, an assumption was made in this study that the entire underground volume of the hydrocarbons produced from a reservoir can be replaced by CO_2. Therefore, the future CO_2 storage capacity of a hydrocarbon reservoir can be calculated from *the underground volume of the ultimately recoverable oil and gas*.

Not every hydrocarbon reservoir is suitable for CO_2 storage, and reservoirs were only analyzed for CO_2 storage if the initial pressure and temperature were above the critical point of CO_2. If the pressure and temperature of the reservoir were unknown, the reservoirs were only analyzed if they were at a depth of 3,000 feet (915 meters) or greater. The generalized theoretical formula adopted in estimating the CO_2 storage capacity of a hydrocarbon field with depth over 3,000 ft (915 m) can be expressed as:

$$Q_{CO2} = (V_{Uoil} + V_{Ugas}) * \rho_{CO_2}, \tag{1}$$

where Q_{CO2} = CO_2 storage capacity (Mt CO_2),
V_{Uoil} = underground volume of the ultimately recoverable oil (km^3),
V_{Ugas} = underground volume of the ultimately recoverable gas (km^3), and
ρ_{CO_2} = CO_2 density at the reservoir conditions (kg/m^3).

The CO_2 density at the reservoir conditions was calculated using correlations from Altunin (1975) that assume that the CO_2 density is a function of the pressure and temperature of the reservoir[4].

The underground volumes of oil and gas in equation (1) are calculated from the standard volumes of oil and gas based on the following conversion formula:

$$V_{Uoil} = V_{oil(st)} * B_o, \text{ and} \tag{2}$$

$$V_{Ugas} = V_{gas(st)} * B_g, \tag{3}$$

where $V_{oil(st)}$ = volume of oil at standard conditions (km^3),
$V_{gas(st)}$= volume of gas at standard conditions (km^3),
B_o = oil formation volume factor, and

[4] The CO_2 density was calculated using a computer code developed by Victor Malkovsky of the Institute of Geology of Ore Deposits, Petrography, Mineralogy and Geochemistry (IGEM) of the Russian Academy of Sciences, Moscow. We converted his FORTRAN code into Visual Basic.

B_g = gas formation volume factor.

In this study, a default B_o of 1.2 is applied for oil. B_g is estimated using the following equation:

$$B_g = (4.8\,P + 93.1)^{-1}, \tag{4}$$

where P = the reservoir pressure (MPa).

Data on the underground volume of the ultimately recoverable oil and gas in a field is generally not available, so equation (1) usually cannot be directly applied to estimate the CO_2 storage capacity of hydrocarbon fields. But in cases information on the amount of original oil in place (OOIP) or original gas in place (OGIP) is known, the ultimately recoverable oil or gas can be estimated as a proportion of OOIP or OGIP:

$$V_{Uoil} = V_{OOIP} * p_{oil}\text{, and} \tag{5}$$

$$V_{Ugas} = V_{OGIP} * p_{gas}, \tag{6}$$

where V_{OOIP} = underground volume of original oil in place (km^3),
V_{OGIP} = underground volume of original gas in place (km^3), and
$p_{oil/gas}$ = volume percentage of OOIP/OGIP that are recoverable (%).

According to the JOULE II report, the average underground volumes of the ultimately recoverable oil and gas are approximately 35% of OOIP and 80-90% of OGIP, respectively. Therefore, when OOIP and OGIP information is available, equation (1), together with equations (5) and (6), gives the formula to estimate the CO_2 storage capacity in hydrocarbon fields.

3.2.1.2 The Adopted "Conservative" Approach

In most cases, information on the OOIP and OGIP for a reservoir is also not available. The best data that is available is the cumulative oil and gas production up to the date when the data was collected. To make use of this data, the cumulative production of oil and gas was used to replace the ultimately recoverable oil and gas in equation (1). This methodology will result in an underestimation of the CO_2 storage capacity, particularly for fields that are in early stages of production. However, this approach provides the ability to calculate consistent estimates of the CO_2 storage capacity for most of the oil and gas fields using available data. Using this methodology, equation (1) can be rewritten as:

$$\widetilde{Q}_{CO2} = (\widetilde{V}_{Uoil} + \widetilde{V}_{Ugas}) * \rho_{CO_2}, \tag{7}$$

where $\widetilde{Q}_{CO2}$ = CO_2 storage capacity (Mt CO_2),
$\widetilde{V}_{Uoil}$ = underground volume of the cumulative oil production (km^3), and
$\widetilde{V}_{Ugas}$ = underground volume of the cumulative gas production (km^3).

Equation (7) was then used as the baseline formula in estimating the CO_2 storage capacity for hydrocarbon reservoirs.

3.2.1.3 Categorizing the CO_2 Storage Potential for Hydrocarbon Reservoirs

Oil and gas reservoirs were classified into different types in terms of their depths and API gravities. Reservoirs that are at least 3000 ft[5] deep are under enough pressure for supercritical CO_2 injection, so this depth is used as an initial criterion for determining whether hydrocarbon fields have CO_2 storage potential. The API gravity, a measurement of oil density which indicates CO_2 miscibility, is used to determine the EOR potential for oil fields. Oil fields with API gravity more than 25^o are classified as fields with miscible CO_2-EOR potential. Oil fields with API gravity between 17.5^o and 25^o are classified as fields with immiscible CO_2-EOR potential. Based on these criteria, the oil fields can be divided into five categories:

1. Fields with miscible CO_2-EOR potential (depth > 3000 ft, API > 25),
2. Fields with immiscible CO_2-EOR potential (depth > 3000 ft, 17.5 < API < 25),
3. Fields with CO_2 storage potential but no EOR potential (depth > 3000 ft, API < 17.5),
4. Fields without CO_2 storage potential (depth < 3000 ft), and
5. Undetermined fields (depth or API missing).

The gas fields are classified into three categories based on the depth information:

1. Fields with CO_2 storage potential (depth > 3000 ft),
2. Fields without CO_2 storage potential (depth < 3000 ft), and
3. Undetermined fields (unknown depth).

3.2.1.4 CO_2 Capacity Estimation Results

The methods presented above were used to estimate the CO_2 storage capacity for oil and gas reservoirs included in the WESTCARB Phase I database (see Figure 3). The database only hosts complete oil and gas field data for the State of California, so we limited our capacity analysis to the state of California.

Panel A of Table 5 summarizes the CO_2 storage capacity for oil fields aggregated by the five categories mentioned above. There are 121 oil fields in California with miscible CO_2 EOR potential and 18 oil fields with immiscible CO_2 EOR potential. These fields with CO_2 EOR potential have a CO_2 storage capacity of 3.4 Gt. The storage capacity of non-EOR oil fields is trivial, amounting to roughly 0.2 Gt.

The CO_2 storage capacity of gas fields, screened by depth, was also estimated using the expression in equation (7). Panel B of Table 5 shows the storage capacity for gas fields aggregated by the three categories mentioned above. The result yielded 128 gas fields with a combined CO_2 storage capacity of 1.7 Gt.

---

[5] 3,000 ft (approx. 914 m) is chosen as a conservative depth threshold. Some studies suggest using 800 m as depth threshold. The result does not differ much from using 800 m as the depth threshold as few fields have depth between 800 m and 914 m.

Table 5. Estimates of CO_2 storage capacity in oil fields and gas fields, California

Fields Group	Number of Fields	Estimated Total Storage Capacity (Mt)
A: Oil Fields		
Oil fields with CO_2 storage potential	176	3,563
Oil fields with miscible CO_2-EOR potential	*121*	*3,186*
Oil fields with immiscible CO_2-EOR potential	*18*	*178*
Oil fields with CO_2 storage capacity but no EOR potential[a]	*37*	*199*
Oil fields without CO_2 storage potential	55	0
Oil fields without depth information	61	0
B: Gas Fields		
Gas fields with CO_2 storage potential	128	1,666
Gas fields without CO_2 storage potential	36	0
Gas fields without enough information	33	0

[a] Oil fields that lack API data are also included.

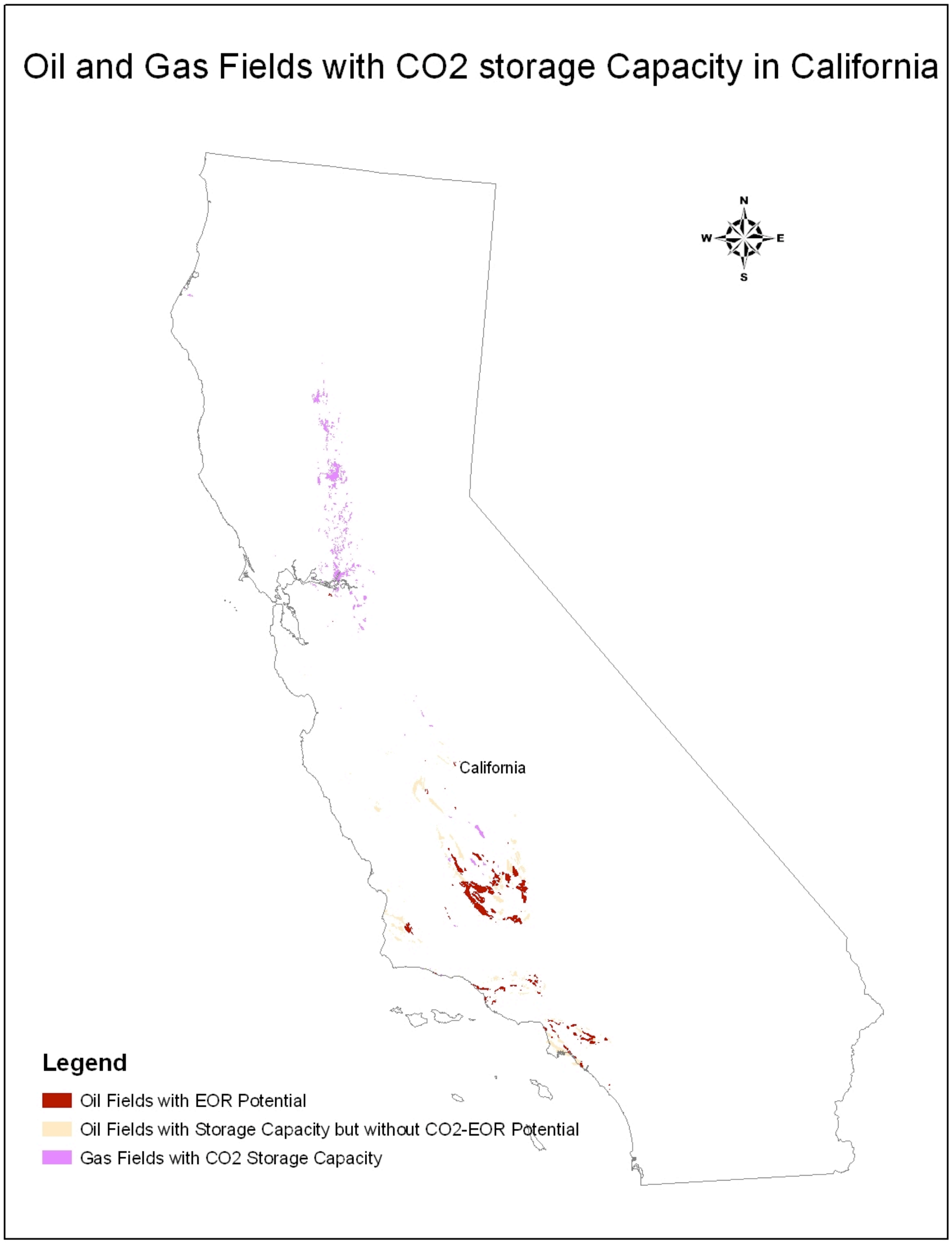


Figure 3. Oil and gas fields with CO_2 storage capacity in Phase I database

3.2.2 CO_2 Storage in Saline Aquifers

The WESTCARB database did not contain complete information for saline aquifers; therefore we are unable to estimate the CO_2 storage capacity of these aquifers in this report. Nonetheless, we include the theoretical model for calculating the CO_2 storage capacity of saline aquifers below.

Deep saline aquifers have the greatest CO_2 sequestration potential since they are the most common and most voluminous type of reservoirs. Two preliminary screening criteria are used to evaluate the CO_2 storage suitability of saline aquifers. The first screening criterion is similar to hydrocarbon reservoirs that the depth of the aquifer needs to be more than 800 m (2,624 ft) to ensure that the injected CO_2 can be kept at the supercritical phase. Second, the aquifer needs to have good seal properties so that the injected CO_2 can be sufficiently trapped in the aquifer.

If the above two screening criteria are satisfied, the CO_2 storage capacity of a saline aquifer can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO_2}, \quad (8)$$

where Q_{aqui} = storage capacity of entire aquifer (Mt CO_2),
V_{aqui} = total volume of entire aquifer (km^3),
p = reservoir porosity (%),
e = CO_2 storage efficiency (%), and
ρ_{CO_2} = CO_2 density at reservoir conditions (kg/m^3).

If accurate spatial data is available for an aquifer, the aquifer volume used in equation (8) can be calculated as an integral of the surface area and the thickness of the aquifer:

$$V_{aqui} = \sum_i S_i T_i, \quad (9)$$

where S_i is the area of the raster cell, and
T_i is the thickness of the cell.

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For the "closed" aquifer, the storage efficiency is assumed to be 2% (Holloway *et al.*, 1996).

The model will be applied to the WESTCARB region to estimate the CO_2 storage capacity of the saline aquifers when more detailed data is available in Phase II.

3.2.3 CO_2 Storage in Coalbeds

The WESTCARB database of Phase I did not contain enough detailed information for coalbeds to estimate the CO_2 storage capacity in the coalbeds. Nonetheless, we include the theoretical model for calculating the CO_2 storage capacity of coalbeds below. In Phase II of the study, efforts will be put into collecting detailed data to apply to the model.

The CO_2 storage capacity of coalbeds used for CO_2-enhanced coalbed methane recovery (ECBMR) operations can be estimated using a methodology based on work by Reeves (2003). The original methodology developed by Reeves is useful for estimates of storage capacity at the basin level. In this study, Reeves's methodology was adapted for use with data collected at the coalfield level.

The principle idea of the CO_2 disposal in coalbeds is that CO_2 can be adsorbed more readily onto the coal matrix than methane. Therefore, the CO_2-ECBMR operation involves absorbing the injected CO_2 at the expense of methane. The displaced methane can be recovered as a free gas at production wells.

The CO_2 storage potential of coalbed results from the two primary mechanisms listed below:

1. Storage capacity via methane replacement: In this process, the primary methane production is assumed to create a voidage in the coal reservoir which can be replaced by CO_2 up to the original pressure of the coal reservoir.
2. Incremental storage capacity via ECBMR: The secondary methane production through CO_2 injection produces additional methane which enables some additional CO_2 storage capacity.

Coalfields are categorized as either "commercial" or "non-commercial" according to the economic feasibility of producing methane from the field. "Non-commercial" areas are areas where ECBMR and CO_2 storage are technically feasible, yet unprofitable. "Commercial" coalfields are those where ECBMR operations are both technically and financially feasible. "Non-commercial" areas are usually deeper, have thinner coals, and are less permeable than the "commercial" areas. The storage capacity of "commercial" coalfields results from both primary and incremental methane replacement, whereas the capacity of "non-commercial" coalfields is from incremental methane replacement. Accordingly, different parameters are used to calculate the storage capacity of the two types of fields via ECBMR. The following two sections discuss details of the methodology for estimating the CO_2 storage capacity for "commercial" methane fields and "non-commercial" methane fields, respectively.

3.2.3.1 CO_2 Storage in "Commercial" Methane Fields

Storage Capacity via Methane Replacement

CO_2 storage capacity available due to methane displacement can be estimated using a coal-rank based ratio that specifies the ratio of the volume of CO_2 that can be injected per volume of CH_4 produced and the primary recovery factor of methane. Due to concerns about reservoir over-pressurization or the ability to gain adequate reservoir access, a voidage replacement efficiency factor (*e*) is used to reflect the percentage of void space occupied by CO_2.

$$Q_{replacement} = r * e * V_{OGIP} * PRF * \rho_{CO_2}\,, \tag{10}$$

where $Q_{replacement}$ = CO_2 storage capacity via methane replacement,
r = CO_2/CH_4 ratio,
e = voidage replacement efficiency,
V_{OGIP} = original gas in place (volume in standard condition),
PRF = primary recovery factor of methane (%), and
ρ_{CO_2} = CO_2 density (in standard condition).

According to Reeves (2003), the baseline value of *e* is 0.75 and the baseline value of *PRF* is 65%. Column (2) of Table 6 gives the CO_2/CH_4 ratio based on the coal rank.

Incremental Storage Capacity via ECBMR

Additional CO_2 storage capacity due to the incremental methane production is estimated using a coal-rank based ratio and the ECBM recovery factor (expressed as a percentage of in-place resource at the start of CO_2 injection).

$$Q_{ECBM} = r * e * V_{OGIP} * (1 - PRF) * ERF * \rho_{CO_2}, \qquad (11)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery,
r = CO_2/CH_4 ratio,
e = voidage replacement and ECBMR efficiency factor,
V_{OGIP} = original gas in place (volume in standard condition),
PRF = primary recovery factor,
ERF = ECBM recovery factor, and
ρ_{CO_2} = CO_2 density (in standard condition).

The baseline values for *e* and *PRF* are 0.75 and 65%, respectively, while the *ERF* depends on the coal rank. Column (3) of Table 6 gives the ECBM recovery factor for each type of coal rank.

Overall Storage Capacity for "Commercial" Methane Fields

The overall CO_2 storage capacity for "commercial" methane fields is the sum of equation (10) and equation (11):

$$Q_{CO_2} = Q_{replacement} + Q_{ECBM}, \qquad (12)$$

Table 6. Coal rank, CO_2/CH_4 ratio, and ECBM recovery factors

(1) Coal Rank	(2) CO_2/CH_4 Ratio	(3) ECBM Recovery Factor ("Commercial" Methane Fields)	(4) ECBM Recovery Factor ("Non-Commercial" Methane Fields)
Low-volatile (LV)	1:1	50%	25%
Medium-volatile (MV)	1.5:1	55%	32%
High-volatile A (HVA)	3:1	61%	37%
High-volatile (HV)	6:1	67%	42%
Sub-bituminous (Sub)	10:1	100%	74%

3.2.3.2 CO_2 Storage in "Non-Commercial" Methane Fields

"Non-commercial' methane fields, though not economically viable for primary methane production, can generate room for CO_2 storage via CO_2-ECBMR. By substituting a zero for the PRF in equation (11), a modified version of the equation (13) can be used to estimate the CO_2 storage capacity for "non-commercial" methane fields.

$$Q_{ECBM} = r * e * V_{OGIP} * ERF * \rho_{CO_2}, \quad (13)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery,
R = CO_2/CH_4 ratio,
e = accessible portion of 'non-commercial' area,
V_{OGIP} = original gas in place (volume in standard condition),
ERF = ECBM recovery factor (%), and
ρ_{CO_2} = CO_2 density (in standard condition).

The default value for *e* for "non-commercial" methane fields is 0.5 (unlike 0.75 for "commercial" fields). Column (4) of Table 7 gives the ECBM recovery factor for "non-commercial" methane fields by coal rank, which is less than the corresponding ECBM recovery factor for "commercial" methane fields within each coal rank type.

3.2.3.3 The "Adopted" Approach to Estimate the CO_2 Storage Capacity for "Commercial" Methane Fields

Equations (10) and (13) use data on the original gas in place in order to estimate the CO_2 storage capacity of methane fields. Just like the case with hydrocarbon fields, however, this data is generally unavailable. For "commercial" methane fields, however, data usually available refer to the cumulative gas production to date. This cumulative gas production data is used as a lower bound of the ultimately recoverable gas—equivalent to the term "V_{OGIP}*PRF" in equation (10). By using this lower bound value of the ultimately recoverable gas, equation (14) gives a very conservative estimate of the CO_2 storage capacity for "commercial" methane fields. Since little data is available for "noncommercial" methane fields, equation (13) is used to estimate the CO_2 storage capacity:

$$Q_{ECBM} = r * e * \widetilde{V}_{CGP} * [\frac{PRF + (1 - PRF) * ERF}{PRF}] * \rho_{CO_2}, \quad (14)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery,
r = CO_2/CH_4 ratio,
e = voidage replacement and ECBMR efficiency factor,
$\widetilde{V}_{CGP}$ = cumulative gas production (volume in standard condition),
PRF = primary recovery factor,
ERF = ECBM recovery factor, and
ρ_{CO_2} = CO_2 density (in standard condition).

Equation (14) was used to estimate the CO_2 storage capacity of “commercial” methane fields using cumulative gas production data. The limitation of this approach was that it underestimated the CO_2 storage capacity for “commercial” methane fields, particularly for those in their early stage of production. Moreover, it could not be applied to “noncommercial” methane fields since these fields have no gas production. In Phase II of the study, effort will be put into collecting original gas in place data for methane fields so that the theoretically more sound formulas (12) and (13) can be used for both “commercial” and “noncommercial” methane fields.

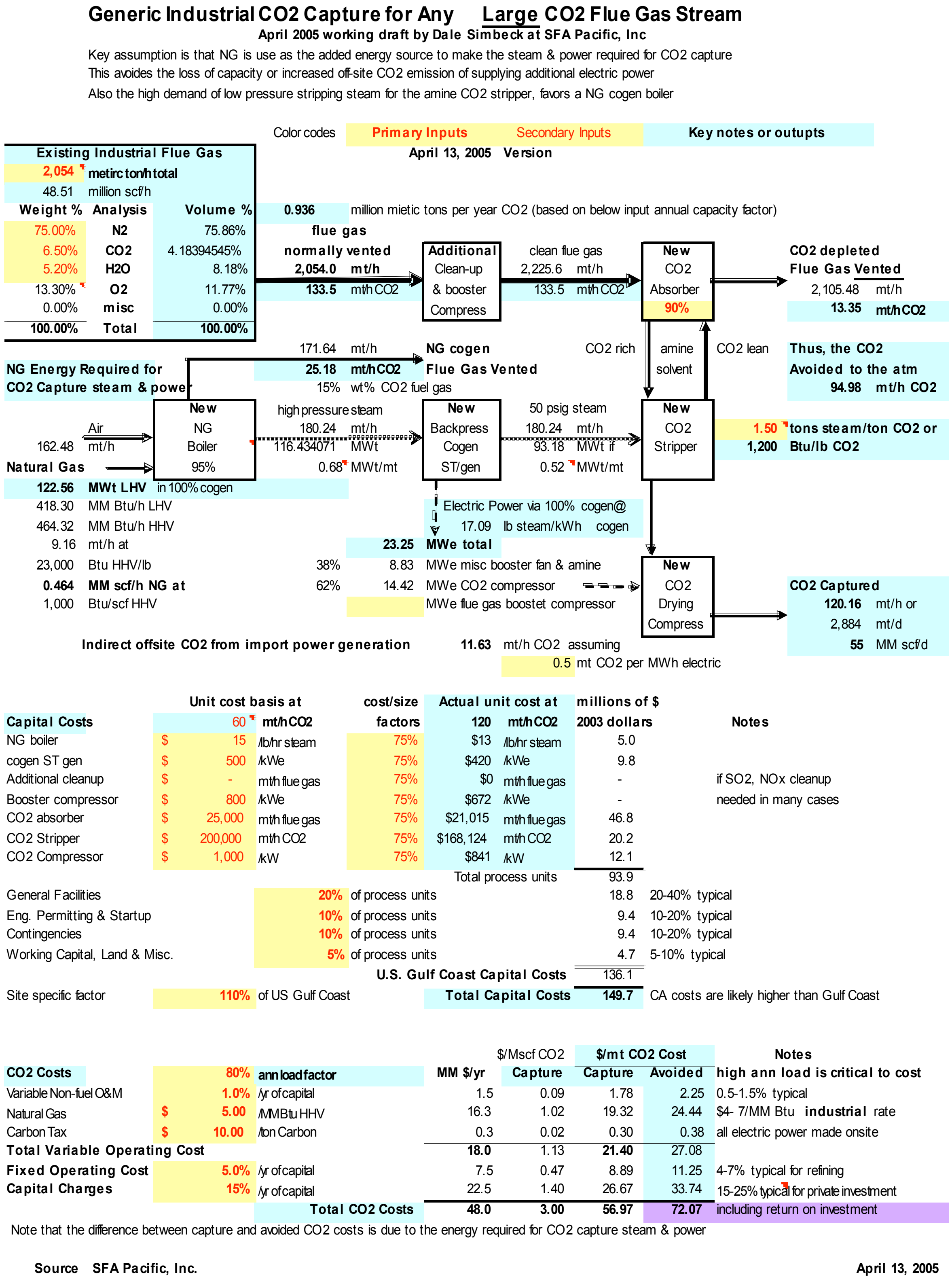
3.3 CO_2 Capture Cost Estimation

3.3.1 Methodology

This study uses the “*Generic* CO_2 *Capture Retrofit*” spreadsheet prepared by SFA Pacific, Inc., as the basis for calculating the CO_2 capture cost for stationary CO_2 sources in the WESTCARB region (see Figure 4). These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour), (2) the flue gas composition (volume share or weight share of CO_2 in flue gas), and (3) the annual load factor.

The SFA Pacific spreadsheet provides estimates of capture cost in terms of both CO_2 captured and CO_2 avoided. CO_2 captured is the amount of CO_2 captured by the absorber and kept out of the atmosphere—assumed to be 90% of the CO_2 in the flue gas. However, since the CO_2 capture process requires energy for purification and compression, the “CO_2 avoided” term subtracts the CO_2 emitted producing this process energy from the total amount of CO_2 captured. The two terms are used differently in CO_2 sequestration analysis. The “CO_2 captured” term is used for calculations involving the amount of CO_2 being handled, such as for pipeline transportation costs, while the “CO_2 avoided” term is used for calculations involving the amount of CO_2 withheld from the atmosphere and therefore eligible for possible CO_2 emissions credits.

According to these two measurements, there are also two definitions on the per-unit CO_2 capture cost. To avoid ambiguity, this report uses “CO_2 capture cost” to refer to the capture cost measured in per tonne CO_2 captured while “CO_2 avoidance cost” to refer to the capture cost measured in per tonne CO_2 avoided.



Generic Industrial CO2 Capture for Any Large CO2 Flue Gas Stream

April 2005 working draft by Dale Simbeck at SFA Pacific, Inc

Key assumption is that NG is use as the added energy source to make the steam & power required for CO2 capture
This avoides the loss of capacity or increased off-site CO2 emission of supplying additional electric power
Also the high demand of low pressure stripping steam for the amine CO2 stripper, favors a NG cogen boiler

Color codes: Primary Inputs | Secondary Inputs | Key notes or outupts

April 13, 2005 Version

Existing Industrial Flue Gas		
2,054	metric ton/h total	
48.51	million scf/h	
Weight %	**Analysis**	**Volume %**
75.00%	N2	75.86%
6.50%	CO2	4.18394545%
5.20%	H2O	8.18%
13.30%	O2	11.77%
0.00%	misc	0.00%
100.00%	Total	100.00%

0.936 million mietic tons per year CO2 (based on below input annual capacity factor)

flue gas normally vented: 2,054.0 mt/h; 133.5 mt/h CO2

Additional Clean-up & booster Compress

clean flue gas: 2,225.6 mt/h; 133.5 mt/h CO2

New CO2 Absorber 90%

CO2 depleted Flue Gas Vented: 2,105.48 mt/h; 13.35 mt/h CO2

171.64 mt/h; 25.18 mt/h CO2; 15% wt% CO2 fuel gas

NG cogen Flue Gas Vented

CO2 rich amine solvent; CO2 lean

Thus, the CO2 Avoided to the atm: 94.98 mt/h CO2

NG Energy Required for CO2 Capture steam & power

Air 162.48 mt/h

Natural Gas

New NG Boiler 95%

high pressure steam: 180.24 mt/h; 116.434071 MWt; 0.68 MWt/mt

New Backpress Cogen ST/gen

50 psig steam: 180.24 mt/h; 93.18 MWt if; 0.52 MWt/mt

New CO2 Stripper

1.50 tons steam/ton CO2 or 1,200 Btu/lb CO2

122.56	MWt LHV	in 100% cogen
418.30	MM Btu/h LHV	
464.32	MM Btu/h HHV	
9.16	mt/h at	
23,000	Btu HHV/lb	
0.464	MM scf/h NG at	
1,000	Btu/scf HHV	

Electric Power via 100% cogen@ 17.09 lb steam/kWh cogen

	23.25	MWe total
38%	8.83	MWe misc booster fan & amine
62%	14.42	MWe CO2 compressor
		MWe flue gas boostet compressor

New CO2 Drying Compress

CO2 Captured: 120.16 mt/h or; 2,884 mt/d; 55 MM scf/d

Indirect offsite CO2 from import power generation: 11.63 mt/h CO2 assuming 0.5 mt CO2 per MWh electric

Capital Costs		Unit cost basis at 60	mt/h CO2	cost/size factors	Actual unit cost at 120	mt/h CO2	millions of $ 2003 dollars	Notes
NG boiler	$	15	/lb/hr steam	75%	$13	/lb/hr steam	5.0	
cogen ST gen	$	500	/kWe	75%	$420	/kWe	9.8	
Additional cleanup	$	-	mt/h flue gas	75%	$0	mt/h flue gas	-	if SO2, NOx cleanup
Booster compressor	$	800	/kWe	75%	$672	/kWe	-	needed in many cases
CO2 absorber	$	25,000	mt/h flue gas	75%	$21,015	mt/h flue gas	46.8	
CO2 Stripper	$	200,000	mt/h CO2	75%	$168,124	mt/h CO2	20.2	
CO2 Compressor	$	1,000	/kW	75%	$841	/kW	12.1	
					Total process units		93.9	
General Facilities				20%	of process units		18.8	20-40% typical
Eng. Permitting & Startup				10%	of process units		9.4	10-20% typical
Contingencies				10%	of process units		9.4	10-20% typical
Working Capital, Land & Misc.				5%	of process units		4.7	5-10% typical
					U.S. Gulf Coast Capital Costs		136.1	
Site specific factor		110%	of US Gulf Coast		Total Capital Costs		149.7	CA costs are likely higher than Gulf Coast

CO2 Costs		80%	ann load factor	MM $/yr	$/Mscf CO2 Capture	$/mt CO2 Cost Capture	$/mt CO2 Cost Avoided	Notes: high ann load is critical to cost
Variable Non-fuel O&M		1.0%	/yr of capital	1.5	0.09	1.78	2.25	0.5-1.5% typical
Natural Gas	$	5.00	/MMBtu HHV	16.3	1.02	19.32	24.44	$4- 7/MM Btu industrial rate
Carbon Tax	$	10.00	/ton Carbon	0.3	0.02	0.30	0.38	all electric power made onsite
Total Variable Operating Cost				18.0	1.13	21.40	27.08	
Fixed Operating Cost		5.0%	/yr of capital	7.5	0.47	8.89	11.25	4-7% typical for refining
Capital Charges		15%	/yr of capital	22.5	1.40	26.67	33.74	15-25% typical for private investment
			Total CO2 Costs	48.0	3.00	56.97	72.07	including return on investment

Note that the difference between capture and avoided CO2 costs is due to the energy required for CO2 capture steam & power

Source SFA Pacific, Inc. — April 13, 2005

Figure 4. SFA Pacific CO_2 capture cost tool

3.3.2 CO_2 Capture Cost for Fossil Fuel Power Plants

In order to use the SFA Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made *that power plants would operate at 80% of their designed capacity once the capture facility has been installed.* So for each fuel type the CO_2 capture cost only varies based on the plant's design capacity. The fossil power plants were grouped into three categories by fuel type: coal-fired, gas-fired, and oil-fired.

Table 7 provides summary statistics for the fossil power plants in the WESTCARB region by fuel type. The WESTCARB database contains 43 power plants[6]. Eleven of these power plants are coal-fired, 29 are gas-fired, and 3 are oil-fired. The actual total CO_2 emissions for these facilities in year 2000 were 131 Mt, while the adjusted (under the assumption of 80% capacity factor) annual CO_2 emissions were 183 Mt.

Table 7. Fossil fuel power plants (PP) by fuel type

Fuel Type	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Plants	11	29	3
Total Design Capacity (MWe)	10,562	23,366	193
2000 Average Operating Factor[b]	0.79	0.47	0.20
Actual 2000 Total CO_2 Emissions (Mt)[c]	77	53	0.3
Adjusted Total Annual CO_2 Emissions (Mt)[d]	81	100	1.6

Note: [a]Weighted (by design capacity) average operating factor
[b]eGRID-published 2000 CO_2 emission based on the actual plant operating factor
[c]Estimated plant CO_2 emissions at 80% operating factor

Two key input variables needed to estimate the CO_2 capture cost for the fossil power plants are the flue gas flow rate and the flue gas composition. Since this specific information was unavailable for all of the power facilities, two further assumptions were used to derive reasonable values for these variables. The two flue gas assumptions were that: (*1) the flue gas flow increases linearly with the design capacity of a power plant; (2) within each fuel-type category, the flue gas composition is independent of the design capacity.* Table 8 provides the flue gas flow rate and composition used in the data for each type of fossil fuel power plant.

[6] The study restricts to power plants that are also contained in the eGRID database and have information on design capacity and 2000 CO_2 emissions.

Table 8. Flue gas flow rate and composition for coal-, gas-, and oil-fired power plants (PP)

		Coal-fired PP	Gas-fired PP	Oil-fired PP[1]
Flow Rate (mt/h per 100MW design capacity)		4.06	5.14	4.6
Flue Gas Composition (% in Volume)				
	N_2	73.81%	75.86%	74.84%
	CO_2	15.15%	4.18%	9.67%
	H_2O	8.33%	8.18%	8.26%
	O_2	2.54%	11.77%	7.16%
	misc	0.16%	0.00%	0.08%

Note: [1]Data about oil-fired power plants are MIT Carbon Capture and Sequestration Technologies Program estimates. Others are from SFA Pacific's *"Generic CO_2 Capture Retrofit"* and *"Existing Coal Power Plant CO_2 Migration"* spreadsheets.

Using data derived from the SFA Pacific capture cost estimation tool, Figure 5 plots both the CO_2 capture cost and avoidance cost for coal-fired power plants as functions of the plant design capacity. The relationship between CO_2 capture and avoidance costs and the design capacity of the coal-fired power plant can be represented by the following two power functions (with R^2 close to 1):

$$yc = 78.57 * x^{-0.1168} \text{, and} \tag{15}$$

$$ya = 99.40 * x^{-0.1168}, \tag{16}$$

where yc = cost per tonne of CO_2 captured ($/t),
ya = cost per tonne of CO_2 avoided ($/t), and
x = design capacity of the coal-fired power plant (MWe).

Taking derivatives on both sides of Equation (15), the CO_2 capture/avoidance cost elasticity with respect to plant design capacity is $\frac{dy/y}{dx/x} = -0.1168$. In practical terms, this means that, due to economies of scale, the per-unit CO_2 capture/avoidance cost decreases by 0.1168 percent for every 1 percent increase in power plant design capacity.

Figures 6 and 7 plot the relationship between the CO_2 capture and avoidance costs and plant design capacity for gas-fired and oil-fired power plants, respectively. Table 9 summarizes the estimated formula for CO_2 capture and avoidance costs as functions of power plant design capacity for each fuel type category.

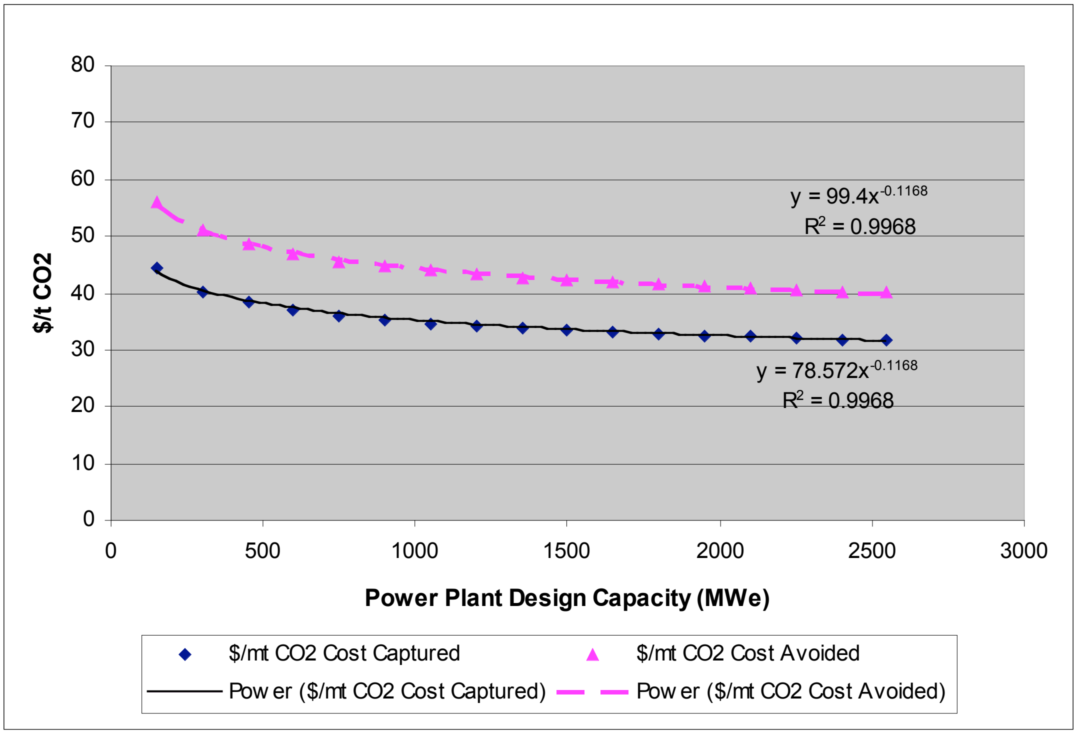


Figure 5. Estimated CO_2 capture and avoidance costs for coal-fired power plants

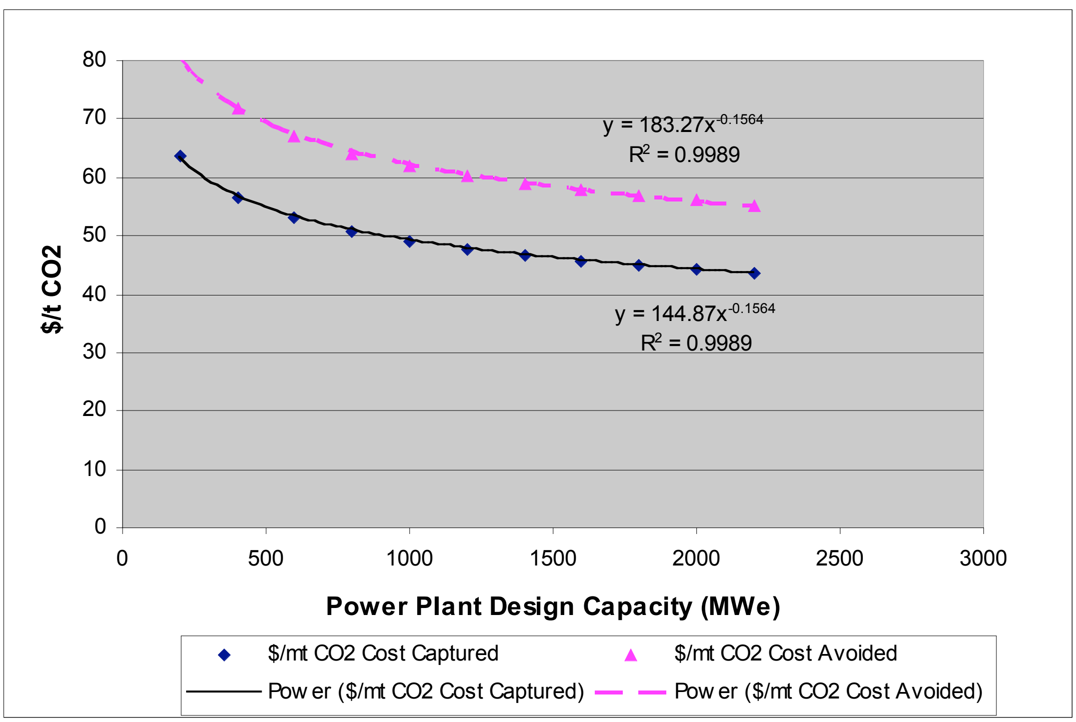


Figure 6. Estimated CO_2 capture and avoidance costs for gas-fired power plants

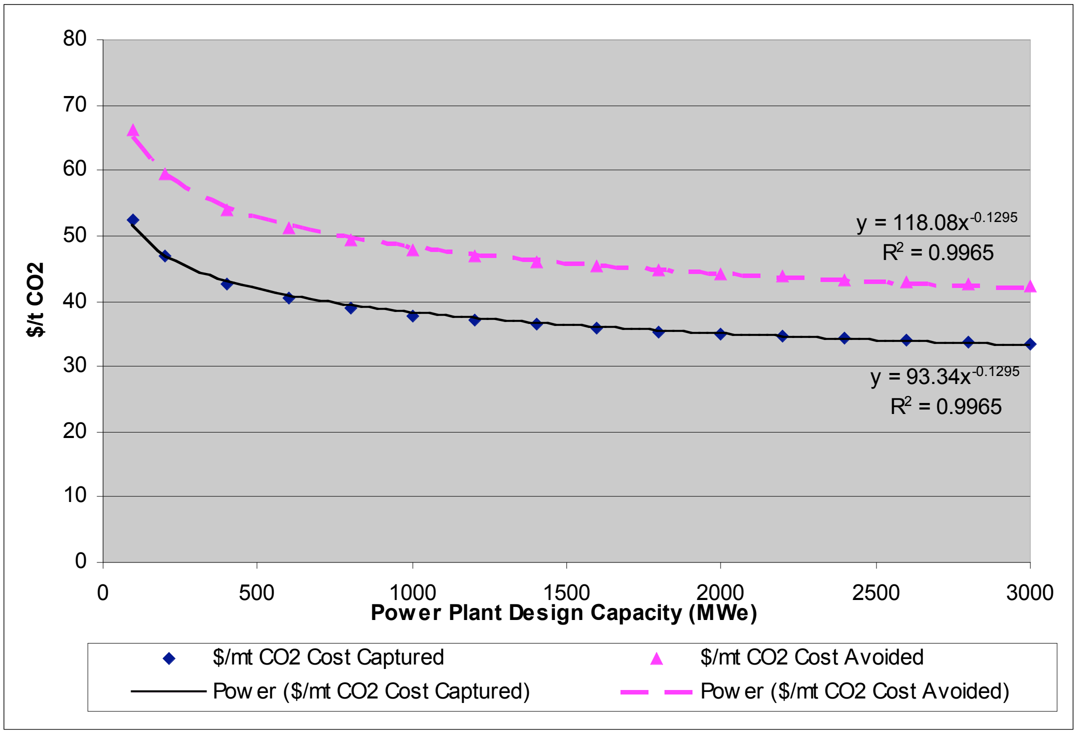


Figure 7. Estimated CO_2 capture and avoidance costs for oil-fired power plants

Table 9. Formula and range of per-tonne CO_2 capture and avoidance cost for power plants

Category	**Coal-Fired PP**	**Gas-Fired PP**	**Oil-Fired PP**
# of Facilities	11	29	3
Capacity Range	28~2,409 MWe	50~2,129 Mwe	112~2951 Mwe
\$/t CO_2 Captured Formula	$78.57x^{-0.1168}$	$144.87x^{-0.1564}$	$93.34\ x^{-0.1295}$
\$/t CO_2 Avoided Formula	$99.40x^{-0.1168}$	$183.27x^{-0.1564}$	$118.08x^{-0.1295}$
Capture Cost Range (\$/t CO_2 captured)	\$31.6~\$53.4	\$44.3~\$79.3	\$49.7~\$62.2
Avoidance Cost Range (\$/t CO_2 avoided)	\$40.0~\$67.5	\$56.1~\$100.3	\$62.9~\$78.6

Note: x is the power plant design capacity in MWe.

The study applies the above methodology to the fossil fuel power plants contained in the WESTCARB database. Column (9) and column (10) in Appendix C present CO_2 capture cost and avoidance cost for these power plants when operated at 80% of design capacity. The capture cost varies from \$31.6 per tonne for a 2,409 MWe coal plant to \$79.3 per tonne for a 50 MWe gas plant. The avoidance cost varies from \$40.0/t to \$100.3/t for these same facilities. The capacity-weighted average CO_2 capture cost for fossil fuel power plants analyzed is \$43.1/t, while the capacity-weighted average CO_2 avoidance cost is \$54.6/t.

3.3.3 CO_2 Capture for Non-power Stationary Sources

The capture cost estimation tool from SFA Pacific was adapted so that it could be used with the non-power sources in the WESTCARB region. In the "Methodology" section, three key variables were needed for the estimation: (1) the flue gas flow rate, (2) the flue gas composition, and (3) the annual load factor. The WESTCARB database includes three types of non-power stationary sources: cement plants, gas processing facilities, and refineries. CO_2 emission data are only available for cement plants and refineries[7], so this study only analyzed the CO_2 capture from these two non-power stationary sources.

Table 10. Assumed flue gas component and load factor for cement plants and refineries

Facility Type	Flue Gas Component (volume)	Annual Load Factor
Cement	25% CO_2, 75%N_2	100%
Refineries	10% CO_2, 90% N_2	100%

Table 10 lists the assumed flue gas composition and the annual load factor used for cement plants and refineries evaluated. The actual flue gas flow rates were unknown, but they were estimated based on plant capacity, the CO_2 emissions factor, and the flue gas composition. Using these assumptions with the generic SFA CO_2 capture model, Figures 8 and 9 plot the per-unit CO_2 capture cost and avoidance cost as power functions of facility capacity for cement plants and refineries, respectively.

[7] The CO_2 emission data for cement plants and refineries were estimated by John Ruby, Nexant, Inc. (email communication with Larry Myer, California Energy Commission and Lawrence Berkeley National Laboratory).

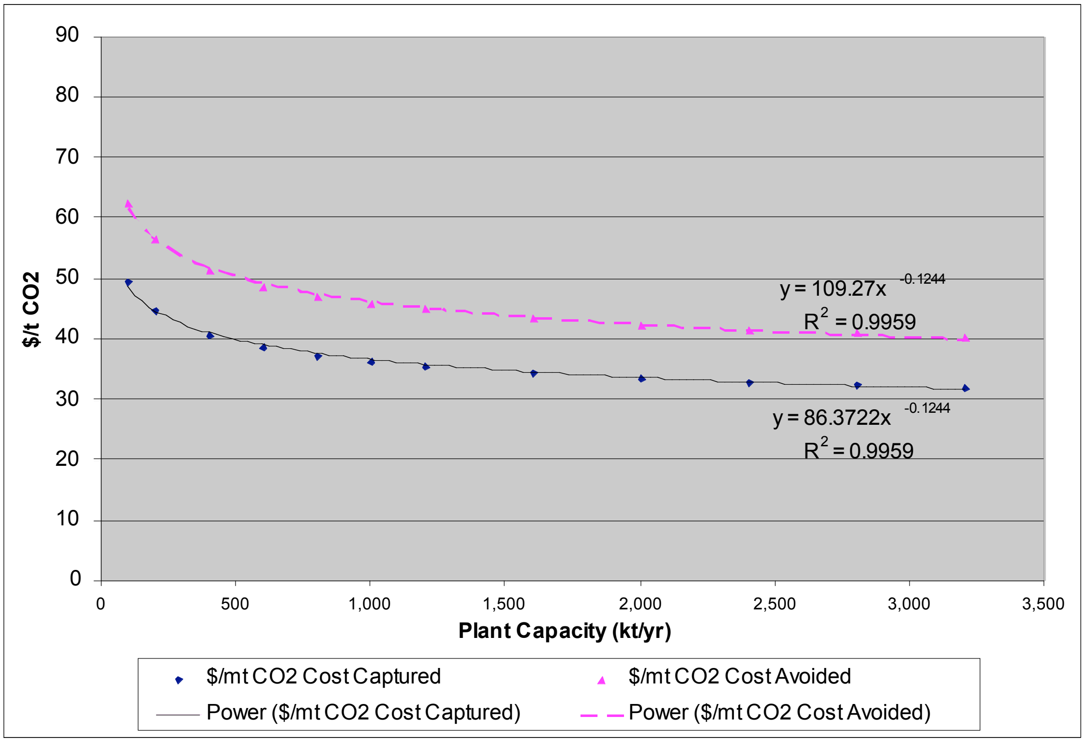


Figure 8. Estimated CO_2 capture and avoidance costs for cement plants

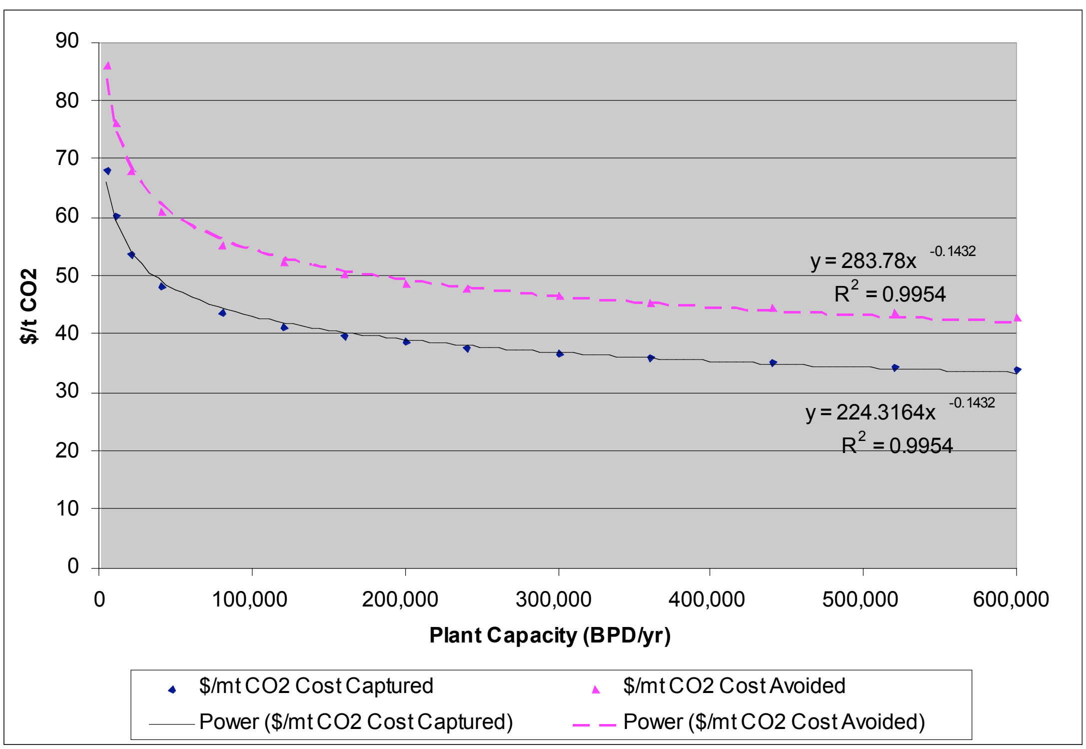


Figure 9. Estimated CO_2 capture and avoidance costs for refineries

Columns (6) and (7) in Appendices D and E show the estimated per-tonne CO_2 capture and avoidance costs for the cement plants and refineries in the region. Table 11 summarizes the range of production capacity, CO_2 capture and avoidance costs for cement plants and refineries evaluated in this study.

Table 11. Range of per-tonne CO_2 capture and avoidance costs for cement plants and refineries

Category	Cement[a]	Refineries
# of Facilities	11	13
Capacity Range	100~2,540 kt	5,400~557,000 BPD
Capture Cost Range ($/t CO_2 captured)	$48.8~$32.6	$65.5~$33.7
Avoidance Cost Range ($/t CO_2 avoided)	$61.7~$41.2	$82.9~$42.7

[a]Five cement plants in the WESTCARB database were excluded due to the lack of production capacity data.

3.4 CO_2 Pipeline Transportation Costs

In cases where the CO_2 source is not co-located with an appropriate sink, large quantities of CO_2 will need to be transported from the source to the sink for sequestration. Underground pipelines are considered the most economical means of transporting such large quantities of CO_2, and a pipeline network would be necessary for carbon sequestration to be feasible. Pipeline construction entails significant capital costs, and this section presents models and methods to estimate the CO_2 pipeline transportation costs based on key pipeline variables.

3.4.1 Transport Pipeline Design Capacity

The pipeline design capacity is one of the first design criteria needed for cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transportation requirements of their corresponding CO_2 emissions sources. For pipelines originating at cement plants and refineries, the pipeline design capacity is set equal to the 2000 CO_2 emissions multiplied by a default capture efficiency (90%). For power plants, the pipeline design capacity is calculated as follows:

$$VC_{CO2} = \frac{VE_{CO2}^{2000}}{OE^{2000}} * CE_0 \quad , \tag{17}$$

where VC_{CO2} = maximum CO_2 flow rate (t/yr),

VE_{CO2}^{2000} = 2000 annual CO_2 emission (t),

OE^{2000} = 2000 plant operating factor, and

CE_0 = default CO_2 capture efficiency (90%).

Equation (17) gives the maximum CO_2 flow rate (in terms of tonnes/yr) for a power plant operating at its full design capacity. The required pipeline capacity is an overestimate since plants usually operate below their maximum design capacity.

3.4.2 Pipeline Diameter Calculation

Figure 10 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. In this study it is assumed that standard type gas industry pipelines will be used for CO_2 transportation (True, 1998). Based on the power function in Figure 10, Table 12 gives the breakdown of the CO_2 flow rate for each pipeline standard diameter within the range from 4 to 36 inches (10 to 91 cm). For any given maximum CO_2 flow rate, Table 12 provides a look-up table to determine the appropriate pipeline diameter. Column (5) of Appendix B provides the corresponding transport pipeline diameter for all sources located in California used in the detailed source-sink matching analysis in the “Least-Cost Path Source-Sink Matching and Full Costing Analysis (California)” section of this paper.

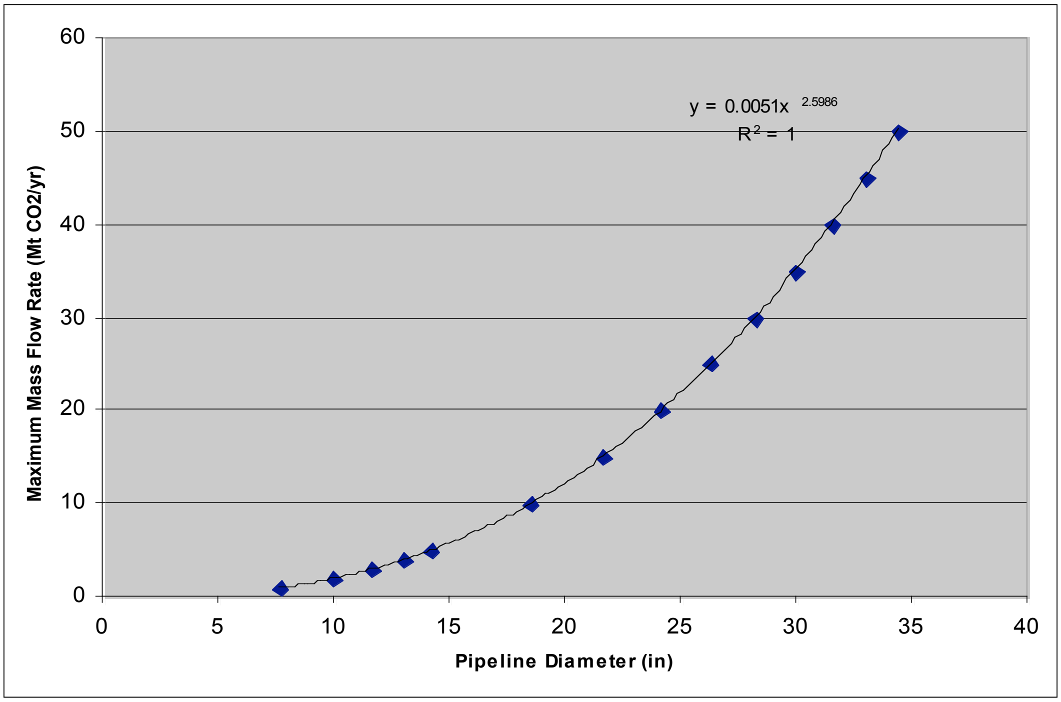


Figure 10. Maximum mass CO_2 flow rate as a function of pipeline diameter

Table 12. Pipeline diameter and the CO_2 flow rate range

Pipeline Diameter (in)	CO_2 Flow Rate (Mt/yr)	
	lower bound	upper bound
4		0.19
6	0.19	0.54
8	0.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

3.4.3 Obstacle Layer Construction

In addition to the diameter and capacity, the terrain being traversed by a pipeline is another significant pipeline construction cost variable. These costs vary considerably according to the local terrain and are also affected by the presence of buildings or infrastructure. Pipeline construction is more expensive in hilly areas than on flat plains. In order to reduce complications and costs, a pipeline's route should avoid passing through populated places[8], wetlands, and national or state parks. In order to account for such obstacles in the study, the locations and characteristics of these obstacles were loaded into Geographic Information System (GIS) software. Using the GIS software, the costs for traversing such obstacles during pipeline construction were combined into a single obstacle data layer. This obstacle layer reflected three types of general obstacles: land slope, protected areas, and crossings of three line-type obstacles (waterways, railroads, and highways).

In order to use this land obstacle data to help calculate optimal pipeline routes, the continuous obstacle data layer was rasterized into 1 km–by–1 km cells. If there were no transportation obstacles contained within a given 1 km^2 cell, then the construction costs of a pipeline traversing the cell was assumed to be "1". From this base case construction cost, relative weights were then assigned to each obstacle in Table 13 according to the difficulty of traversing the obstacle. These relative weights were then added to the base case construction cost to form a combined pipeline construction cost factor.

Table 13. Estimated relative construction cost factor

Construction Condition		Cost Factor
Base Case		1
Slope		
	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area		
	Populated Area	15
	Wetland	15
	National Park	30
	State Park	15
Crossing		
	Wateway Crossing	10
	Railroad Crossing	3
	Highway Crossing	3

Note: The relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base-case construction cost for an 8-inch pipeline.

The total pipeline construction cost factor for a cell is then the sum of the base case cost factor and the cost factors of all of the obstacles that exist in that cell. For example, the relative cost of an 8-inch pipeline crossing a river in the national park would be 41: 1 (base case) + 30 (national park) + 10 (river crossing). Using the weighted cost layer calculated above, the spatial analysis function in ArcGIS was used to determine the least-cost pipeline path for connecting each source and sink.

[8] The populated places data is from U.S. Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

3.4.4 Pipeline Transport Cost Estimation

The model decomposes the pipeline construction cost into two components: the basic pipeline construction cost (diameter-dependent) and the additional obstacle cost (diameter-independent). The basic pipeline construction cost is estimated to be \$12,000/in/km[9] (\$7,602/cm/mi). The additional obstacle cost was calculated as the product of the relative weight assigned in Table 13 and the basic construction cost of an 8-inch pipeline[10]. The additional obstacle cost does not vary with the pipeline diameter, since the amount of site preparation required for pipeline construction does not vary according to pipeline size. The cumulative pipeline construction cost was then calculated as the sum of the basic construction cost and the additional obstacle cost.

For pipeline operations the pipeline operations and maintenance (O&M) costs were estimated to be \$3,100/km (\$4,991/mi) per year, regardless of pipeline diameter (Heddle *et al.*, 2003). A capital charge of 0.15 was used to annualize the construction cost over the operating life of the pipeline so that the annual pipeline transportation was 0.15 of its construction cost plus the annual O&M cost.

---

[9] Heddle *et al.* (2003) estimate that the average pipeline construction cost (including obstacle crossing cost) is \$20,989/in/km. For sparsely populated areas average pipeline construction costs are estimated to be \$12,400/in/km.

[10] For a 100-km, 8-inch pipeline with 6 waterway crossings, 1 railroad crossing, 1 highway crossing, and 1 wetland crossing, the estimated construction cost is (\$12,000/in/km)*(8 in)*(100 km) (base case construction) + \$960,000*6 (waterway crossing) + \$288,000 (railroad crossing) + \$288,000 (highway crossing) + \$1,440,000 (wetland crossing) = \$17,376,000, which is similar to the average number provided by Heddle: (\$20,989/in/km)*(8 in)*(100 km) = \$16,791,200.

3.5 Distance-Based Source-Sink Matching

This section presents the methodology developed to estimate the distance from each CO_2 source to its nearest sink. This methodology was applied to sources and sinks in the WESTCARB region in order to estimate the transportation requirements for captured CO_2 and to study how these requirements changed as a function of the sink set included in the analysis. The results from this analysis provide estimates of the distance between sources and their closest sinks, but do not consider the transportation costs or optimal pipeline routing when matching, as will be considered in "Least-Cost Path Source-Sink Matching and Full Costing Analysis (California)" section.

The source-sink matching in the WESTCARB region considers 37 power producing CO_2 sources and 21 non-power producing CO_2 sources. Over an assumed 25-year project lifetime, 4.6 Gt of CO_2 would need to be sequestered[11]. The regional CO_2 storage capacity was estimated to be at least 5.2 Gt. Since the estimated CO_2 storage capacity was larger than the amount of captured CO_2, an assumption was made in this analysis that all sources could be transported and stored in the nearest sinks. The sink storage capacity constraint was considered in the analyses presented in the following section.

3.5.1 Methodology

This analysis was used to calculate the straight-line distance from each CO_2 source to the nearest sink and provides an estimate of the CO_2 storage potential within a given distance from the CO_2 sources. The analysis was performed using GIS software tools. The "Straight-Line Distance" function in the spatial analyst extension of ArcMap was used to calculate the shortest straight-line distance from each source in the study area to the nearest geological sink. The output from this analysis was a raster layer where the cell values were equal to the straight-line distance from each cell to the nearest sink.

3.5.2 Straight-Line Distance-Based Source-Sink Matching in WESTCARB Region

The CO_2 sources without emission data were excluded from the source-sink matching analysis. We also limited our analysis to the contiguous-U.S. part of the WESTCARB region and excluded the CO_2 sources located in Alaska. Fifty-eight CO_2 sources in WESTCARB region, including 10 coal-fired power plants, 27 gas-fired power plants, 11 cement plants and 10 refineries, are included in analysis. The total annual CO_2 emission for these sources is about 184 Mt.

The distance matching analysis was performed for each of the four groups of eligible sinks: 1) oil and gas fields with EOR potential, 2) all oil and gas fields, 3) saline aquifers, and 4) all geological sinks. Since the WESTCARB server lacked sufficient data to evaluate the CO_2 sequestration potential in Nevada saline aquifers, we performed the source-sink matching analysis under two scenarios, either with (Scenario One) or without (Scenario Two) including

[11] The CO_2 emissions were estimated under an operation capacity of 80% for power plants and full production capacity for non-power stationary CO_2 sources. A capture efficiency of 90% is also assumed for all the CO_2 except for the pure CO_2 sources.

Nevada saline aquifers. Figure 11 presents a map of all the sources and sinks considered in this section.

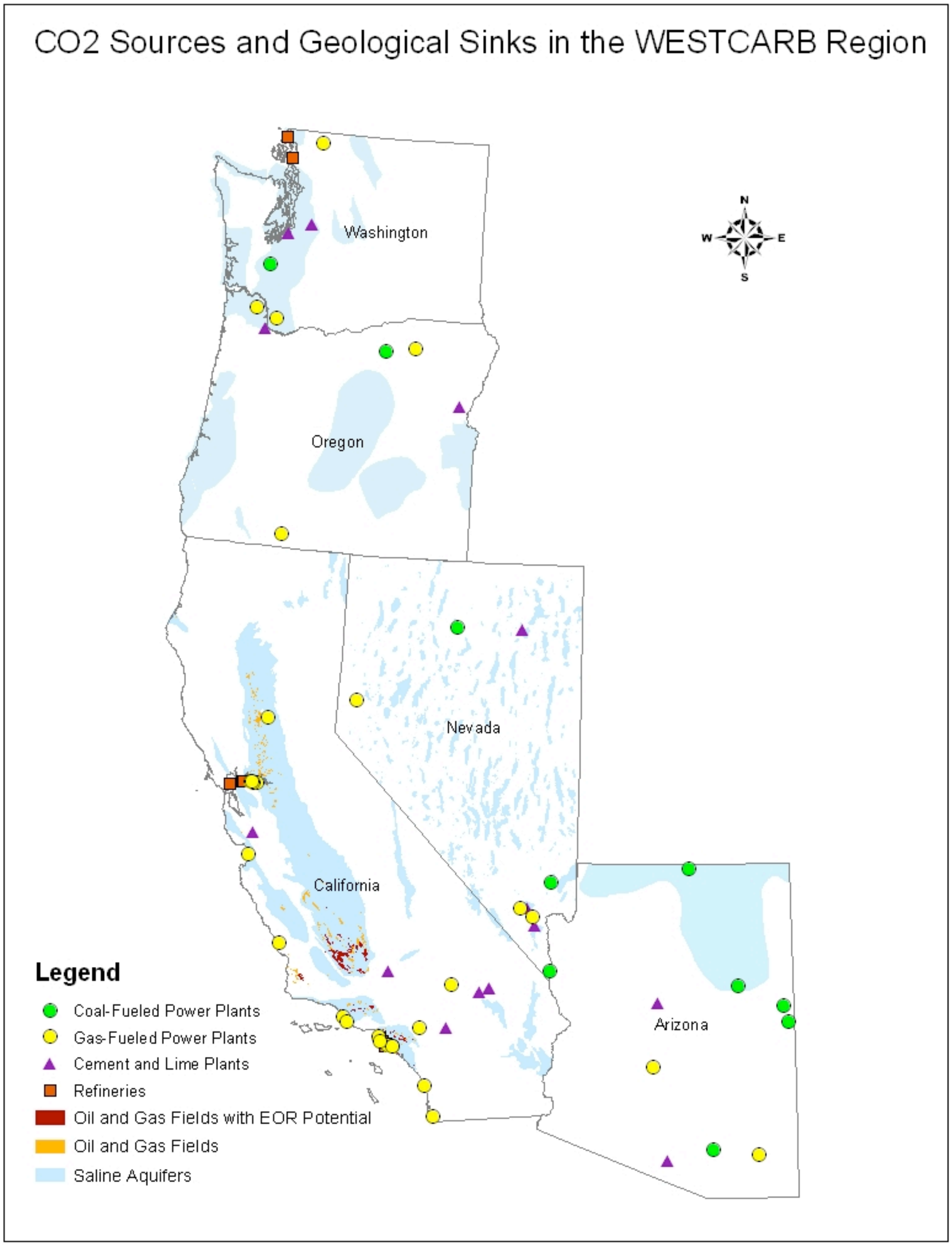


Figure 11. CO_2 sources and sinks considered in straight-line distance matching

3.5.2.1 Scenario One: Nevada Aquifers Included

Table 14, Figure 12, and Figure 13 show the results for the source-sink matching in the WESTCARB region when the Nevada aquifers are included. Appendix C to Appendix E presents the detailed results with the straight-line distance to nearest EOR site, oil & gas field, and aquifer, respectively, for each CO_2 source. It's interesting to note that the cases with the hydrocarbon reservoirs needed much larger transportation distances than the cases with the saline aquifers. This is probably due to the limited amount of hydrocarbon data for states other than California. Also, performing the analysis with all sinks is identical to the aquifer-only cases since many hydrocarbon fields are geographically located within the bounds of aquifers.

Table 14. Annual CO_2 storage capacity (Mt) by marginal straight-line distance to nearest sink; Nevada aquifers included

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km (31 mi) or less	100 km (62 mi) or less	250 km (93 mi) or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in Region	154	174	176
All Sinks	154	174	176

Note: The annual CO_2 storage rate was 184 Mt.

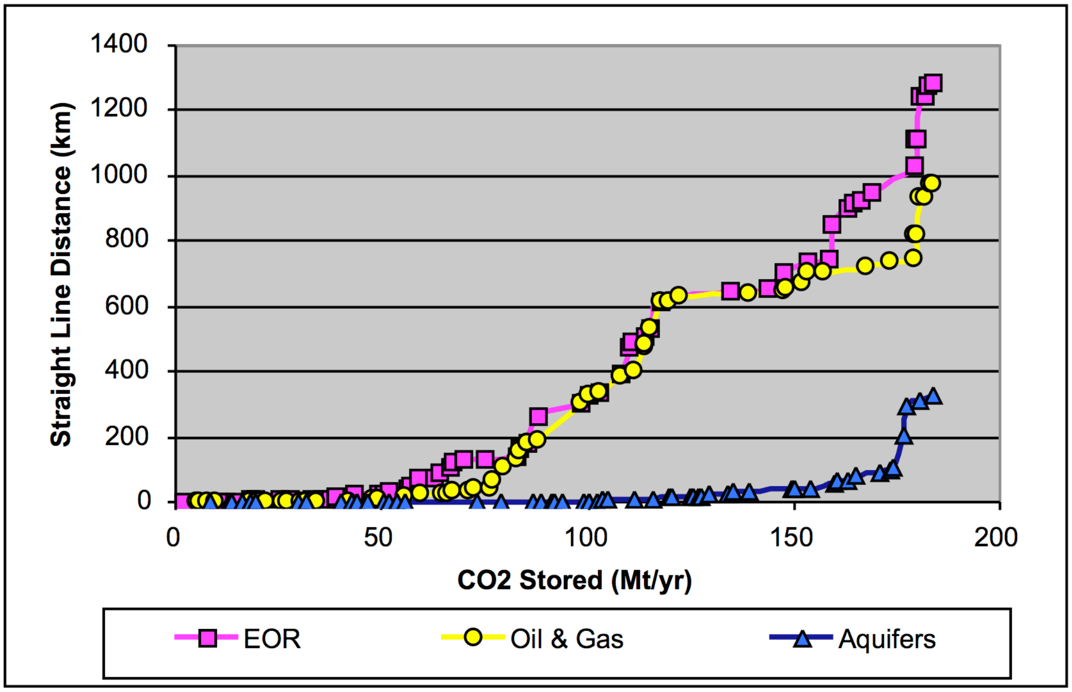


Figure 12. Marginal straight-line distance from CO_2 source to sink by annual CO_2 storage rate; Nevada aquifers included

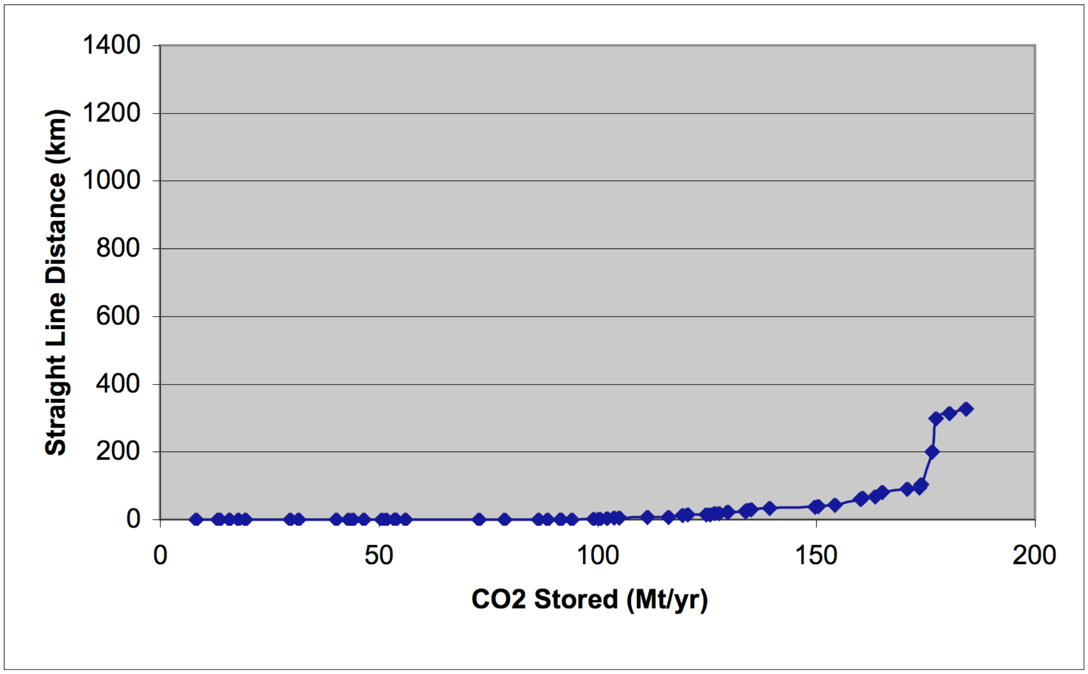


Figure 13. Marginal straight-line distance from CO_2 source to all sinks by annual CO_2 storage rate; Nevada aquifers included

3.5.2.2 Scenario Two: Nevada Aquifers Excluded

Table 15, Figure 14, and Figure 15 present the results for the case when the Nevada aquifers are excluded. It's interesting to note that the exclusion of the Nevada saline aquifers did not appear to have any significant effect on the results.

Table 15. Annual CO_2 storage rate (Mt/yr) by marginal straight-line distance to nearest sinks; Nevada aquifers excluded

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km (31 mi) or less	100 km (62 mi) or less	250 km (93 mi) or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in Region Excluding Nevada	139	168	176
All Sinks	139	168	176

Note: The annual CO_2 storage rate was 184 Mt.

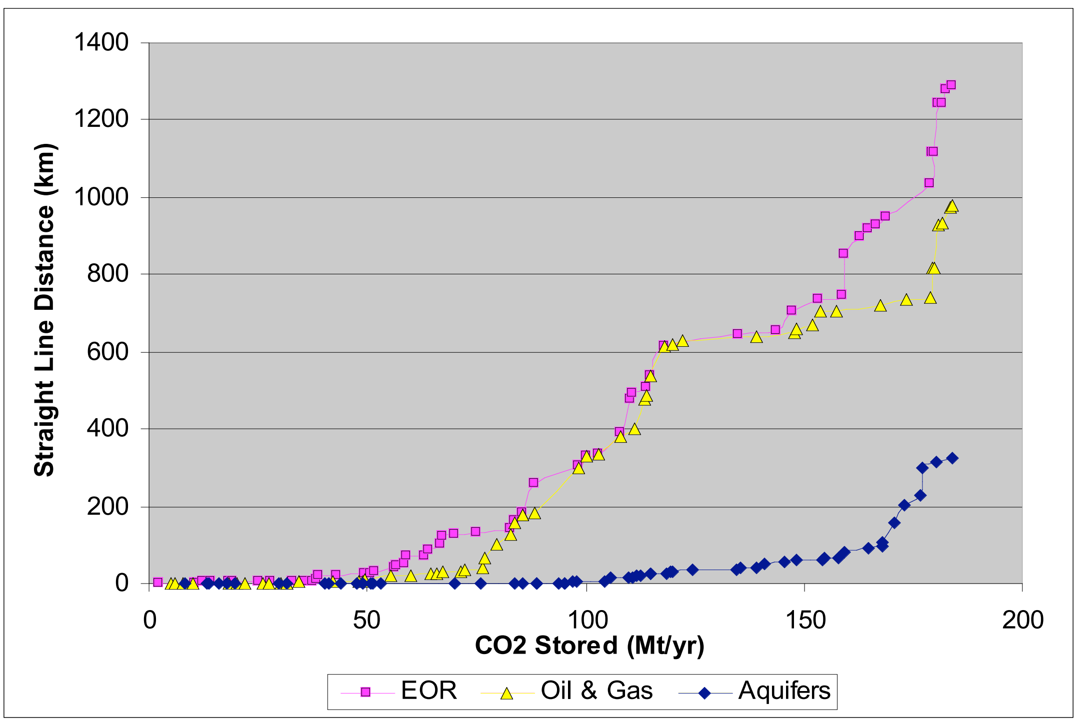


Figure 14. Marginal straight-line distance from CO_2 source to all sinks by annual CO_2 storage rate; Nevada aquifers excluded

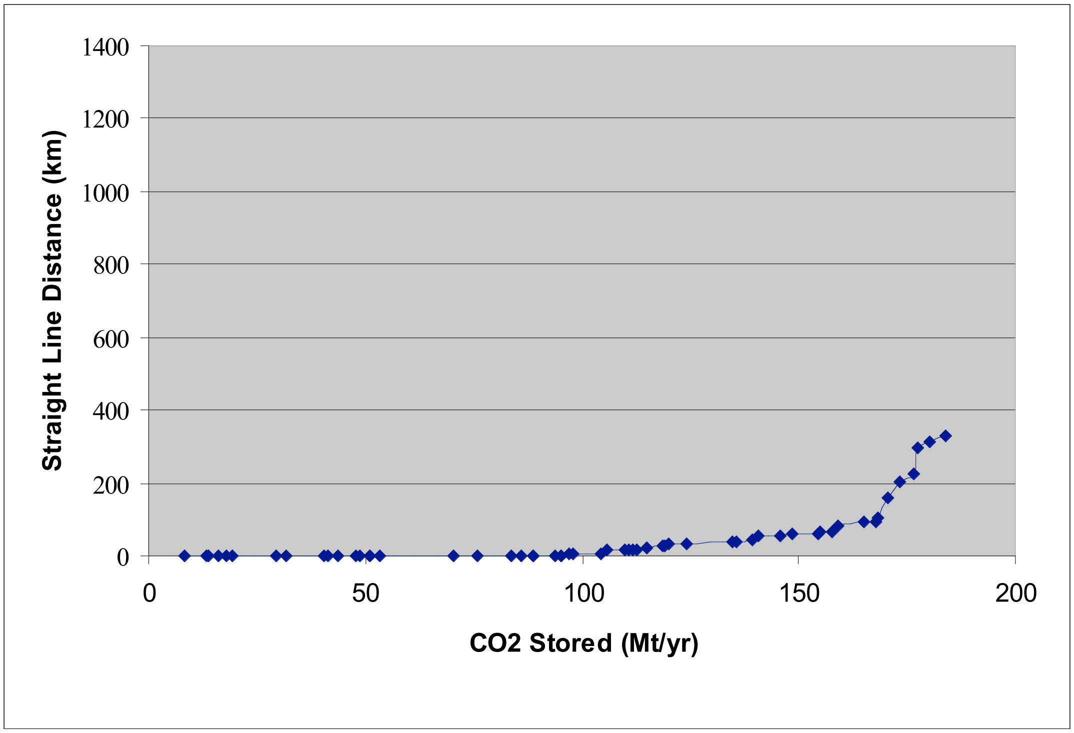


Figure 15. Marginal straight-line distance from CO_2 source to nearest sinks by annual CO_2 storage rate; Nevada aquifers excluded

3.5.3 Source-Sink Matching Discussion

This section presents results from analyses of the straight-line distance between sources and sinks in the WESTCARB region. While these results are not an accurate representation of the total cost for carbon capture and storage (CCS; also called carbon sequestration) within the WESTCARB region, the results do provide a sense of the CCS transportation requirements for cases where there is insufficient information for a full-cost evaluation. If EOR sites in the WESTCARB region were the only sinks available for sequestration, only less than half of the CO_2 sources by volume could be matched with a sink that were less than 250 km (155 mi) from the source; and, for some sinks in Washington State, the closest EOR sinks would be over 1000 km (621 mi) away. If all sink types were considered for sequestration, however, more than 95% of the CO_2 sources could be matched with appropriate sinks within 250 km (155 mi) of the source. More than 75% of the sources (by volume) would find their nearest sinks within 50 km (31 mi) of the source. Approximately 50% of the sources were actually co-located with an appropriate sink, which was usually a saline aquifer. It's also interesting to note that the exclusion of the Nevada saline aquifers did not appear to have any significant effect on the results. The actual transportation distance requirements would be larger if sink capacity constraints and transportation obstacles were considered. These analyses are presented in the following section.

3.6 Least-Cost Path Source-Sink Matching and Full Costing Analysis (California)

In this section, estimates of the total cost of carbon capture and storage are calculated by combining the methods presented in both the "CO_2 Capture Cost Estimation" section and the "CO_2 Pipeline Transportation Costs" section for calculating capture and transportation costs with a more detailed method of calculating pipeline paths. Whereas in the previous section pipeline paths were calculated according to the shortest distance, in this section the pipeline paths were calculated using an iterated GIS-based least-cost path algorithm that considers typography as well as social and political data for the study region. This more-cumulative sequestration cost analysis, which consists of capture, transport, and injection costs, was performed only for the State of California due to the limited availability of detailed data for the entire WESTCARB region. As more detailed data is collected for the other WESTCARB states in Phase II, this least-cost path source-sink matching and full capture-cost analyses will be extended to the entire WESTCARB region.

3.6.1 Methodology

In contrast to the distance-based matching analysis performed in the "Distance-Based Source-Sink Matching" section, this section presents a method of matching sources and sinks based on least total cost. For this analysis, each CO_2 source in California was linked to a least-cost geological sink based on a least-cost transportation route and an estimated injection cost. The linking algorithm also considered reservoir storage capacity and ensured that each linked sink had sufficient storage capacity for all sources matched with it.

The list of sinks used in the matching analysis included hydrocarbon fields with EOR potential, hydrocarbon fields without EOR potential, and saline aquifers[12]. While all of these sinks are suitable for sequestration, the cost of sequestration varies for each sink type. The sinks can be grouped into two basic categories: (1) oil fields with EOR potential that are eligible for oil production credits, and (2) non-EOR hydrocarbon fields and saline aquifers that will have to bear the full cost for CO_2 transportation, compression, and injection. Projects were assumed to have 25-year lifetimes, and sources were only matched up to a sink if its remaining storage capacity exceeded the source's 25-year CO_2 flow.

The linking analysis was conducted in two stages, first considering cheaper sinks before proceeding to sinks with higher storage costs. In this first stage, EOR sites were included as potential sinks since they would purchase CO_2 from a provider. After allocating the EOR storage capacity to the appropriate sources, if there were still unmatched CO_2 sources, the matching algorithm was rerun with the regular hydrocarbon fields and saline aquifers included in the list of potential sinks. An algorithm flow chart is shown in Figure 16.

[12] There are no coalbed methane fields included in the sink set for California.

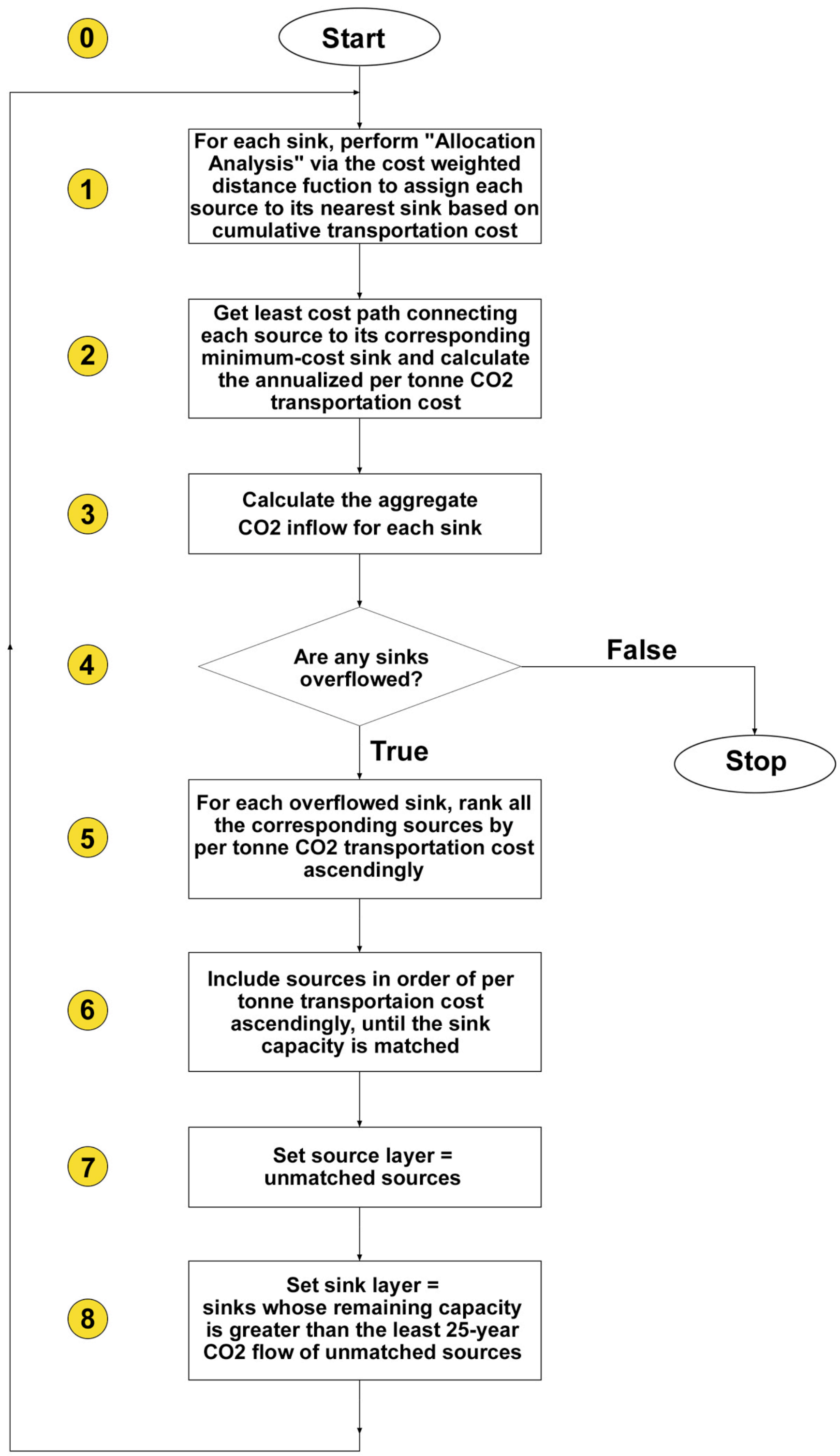


Figure 16. Flow chart of the least-cost path CO_2 source-sink matching algorithm

An iterative algorithm was developed to "optimize" the source-sink matching using the ArcGIS "spatial analysis" tool. Figure 16 depicts the flow chart for this iterative matching algorithm using an example of a stage-1 matching process when only transportation-cost needs are considered:

- In the first step, the ArcGIS "Allocation Analysis" function was used to assign each source to its nearest sink based on the transportation cost as calculated in the "CO_2 Pipeline Transportation Costs" section. The allocation result provided a picture of how the sources would be optimally linked to the sinks within the region if there were no restrictions on the storage capacity of each sink.

- In the second step, the ArcGIS "Least Cost Path" function was used to obtain the least-cost path linking each source to its corresponding least-cost sink. Using the transportation cost estimation algorithm discussed in the "CO_2 Pipeline Transportation Costs" section, the capital cost and maintenance cost were calculated as the cost-per-tonne of CO_2 transported.

- In the third step, the 25-year CO_2 flow volumes from all sources assigned to each sink in step 1 were summed up to get the aggregate 25-year CO_2 flow.

- In step 4, the aggregate 25-year CO_2 flow calculated in step 3 was compared to the estimated CO_2 storage capacity for each sink.

  - If none of the sinks were over capacity, then the iteration ended with an approximately "optimal" matching outcome.

  - If some of the sinks were over capacity, the program continued to step 5 to evaluate which sources should be excluded from the "overfilled" sinks.

- In step 5, for each "overfilled" sink, the associated sources were ranked in ascending order by the transportation cost per tonne of CO_2.

- In step 6, the ordered sources for each "overfilled" sink were re-added to the sink's "matched source set" in ascending order of CO_2 transportation cost. Sources were added until the sink's remaining storage capacity was less than the 25-year CO_2 flow of the smallest source assigned to this sink in step 1 that had not been added to the "matched source set."

- In step 7, all of the sources that were not included in "matched source set" for any sinks were set as the new "source layer".

- In step 8, all sinks with remaining CO_2 storage capacity exceeding the 25-year CO_2 flow of the smallest source in the new "source layer" defined in step 7 was set as the new "sink layer". The program then went back to step 1 and reran the source-sink matching algorithm until all sources were matched and no sinks were "overfilled."

While the matching algorithm described above was capable of determining a near-optimal solution, the algorithm might not find the absolute least-cost solution. Since the algorithm did not evaluate whether assigning one source to a relatively more costly sink could reduce overall system cost, the optimization was not truly optimal. Even though the matching algorithm used in this analysis was not "truly optimal," this is a typical problem in system optimization and the algorithm produces a reasonable result. The complexity of a "true" system optimization algorithm was beyond the scope of the Phase I analysis, but efforts in Phase II will focus on improving the algorithm functionality.

3.6.2 Least-Cost Path Source-Sink Matching

This analysis was conducted using the CO_2 sources located in California, which included power plants, refineries, and cement and lime plants. Gas processing plants were excluded from the analysis since the server lacked CO_2 emissions data for these facilities. In total, 31 sources were included in the source-sink matching process. The project lifetime was assumed to be 25 years. Total source CO_2 flow over 25 years was approximately 2.1 Gt. Table 16 shows the CO_2 flow rate by source type.

Table 16. CO_2 flow rate by plant type in California

Plant Type	Number of Plants	Annual CO_2 Flow (Mt)	25-year CO_2 Flow (Mt)
Cement and Lime Plant	6	5	135
Power Plant	18	70	1,754
Refinery	7	10	255
All sources	31	86	2,144

Oil fields with EOR potential are chosen as the geological sinks in the matching process. There are 139 oil fields with EOR potential in California. 121 of these fields, or 3.4 Gt of the capacity, were favorable for miscible EOR operations. 18 of the fields, or 0.2 Gt of the capacity, were categorized as immiscible EOR reservoirs. After screening out fields with storage capacity less than 20 Mt[13], 35 sinks with an overall storage capacity of 3.2 Gt were included in the first stage of the analysis. Since the CO_2 storage capacity in EOR sinks was larger than the 25-year CO_2 flow, we expected to link all the sources to their least-cost EOR sinks. Nevertheless, regular hydrocarbon fields and saline aquifers were also prepared as the back-up sink layer in case there would be some unmatched CO_2 sources in the first stage.

The cost surface used in this study is an aggregate transportation cost layer generated using the method presented in the "CO_2 Pipeline Transportation Costs" section. The value of each cell in this layer is the obstacle cost factor plus the construction cost factor for an 8-inch pipeline crossing this cell. The raw data source of each type of obstacle is listed in Table 17.

---

[13] Most of the CO_2 sources will emit more than 20 Mt CO_2 over the 25-year project lifetime.

Table 17. Data sources of transportation barrier layers

Barrier Layer	Raw Data Source
Slope	ESRI Digital Elevation Model Data
Populated area	ESRI Data & Maps
Wetland	USGS LULC Data
National Park	ESRI Data & Maps
State Park	ESRI Data & Maps
Waterway	ESRI Data & Maps
Railway	ESRI Data & Maps
Highway	ESRI Data & Maps

Figure 17 shows all the CO_2 sources, geological sinks, and transportation cost factors used in the least-cost path analysis. After the first stage of the source-sink matching analysis, all the 35 sources were linked to EOR sites as expected.

The transportation cost (including construction cost, obstacle-crossing cost, and O&M cost) of each source can be calculated using the method presented in the "CO_2 Pipeline Transportation Costs" section. Table 18 shows the results of the source-sink matching and the transportation cost analysis in California. CO_2 sources are sorted in ascending order by the transportation cost.

Figure 18 plots the marginal transportation distance by annual CO_2 storage rate for sources transported to the oil fields with EOR potential. Figure 19 plots the marginal transportation cost by annual CO_2 storage rate for sources transported to EOR oil fields.

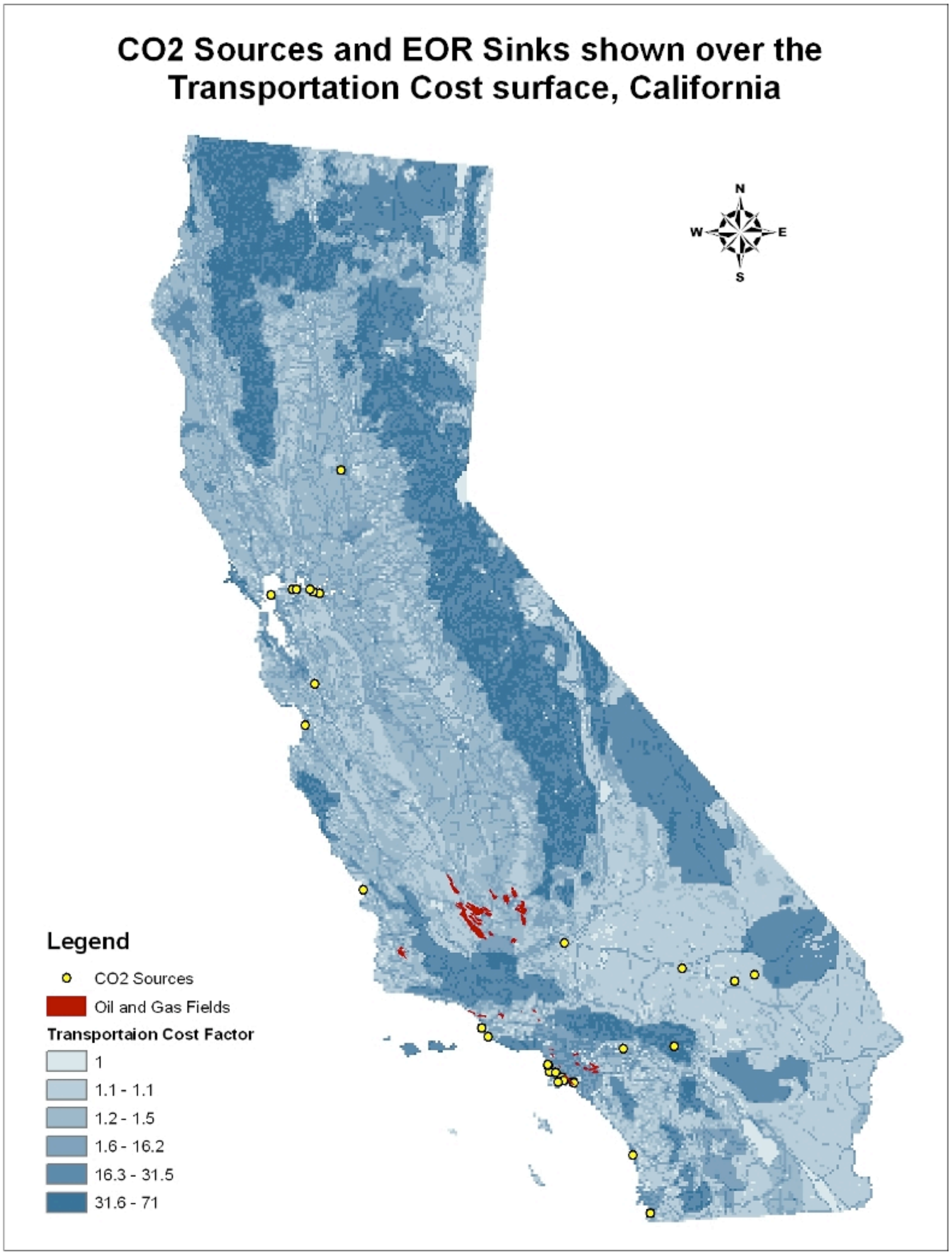


Figure 17. CO_2 sources and sinks shown over the transportation cost surface, California

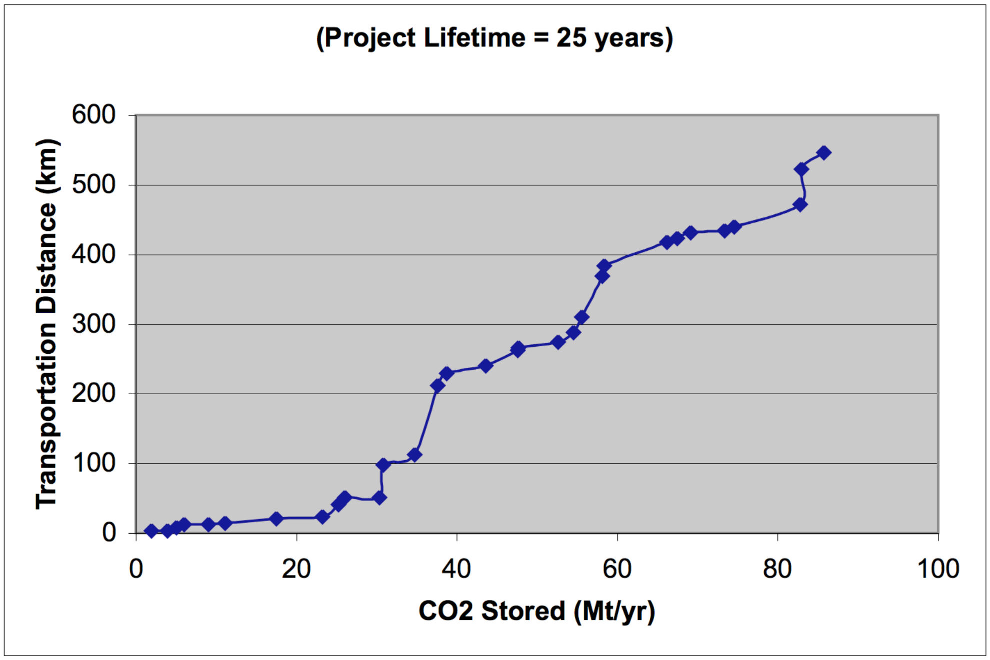


Figure 18. Marginal transportation distance by annual CO_2 storage rate in oil fields with EOR potential, California

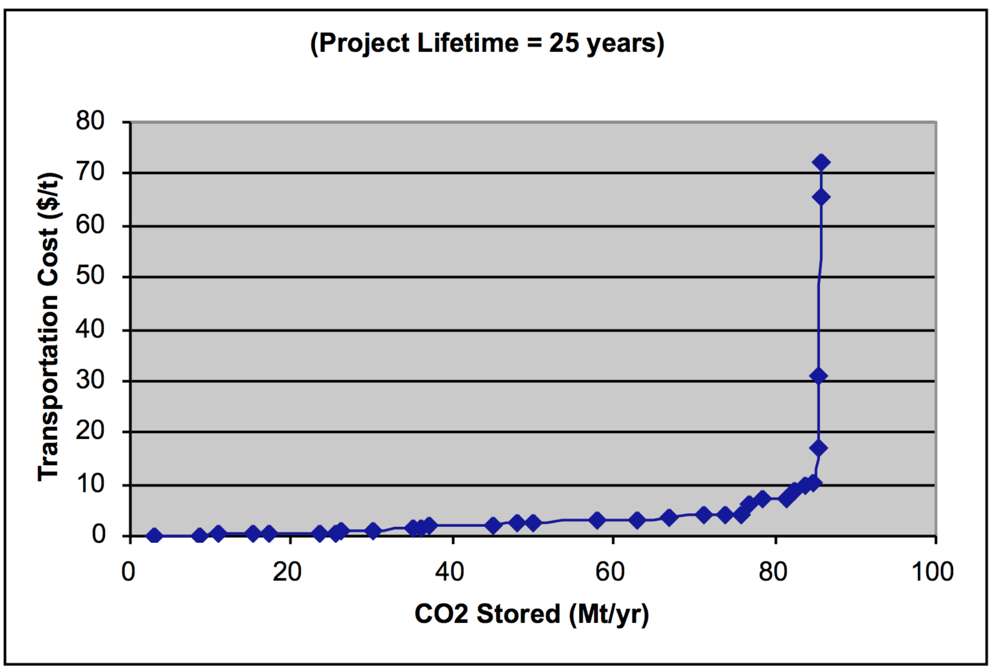


Figure 19. Marginal transportation cost by annual CO_2 storage rate in oil fields with EOR potential, California

Table 18. Least-cost path analysis for CO_2 sources transported to oil fields with EOR potential, California

Facility Name	Plant Type	Destination Fieldcode	Pipeline Diameter (inch)	25-year CO2 Flow (Mt)	Length (km)	Construction Cost (M $)	Crossing Cost (M$)	Annual O&M Cost (M$)	Transportation Cost ($/ton)
Scattergood Generating Station	POWER PLANT	LA021	16	74.69	13	2.51	0.83	0.04	0.18
Ormond Beach Generating Station	POWER PLANT	VE076	20	144.52	24	5.78	3.55	0.07	0.25
Mandalay Generating Station	POWER PLANT	VE076	12	52.59	15	2.17	2.58	0.05	0.36
Etiwanda Generating Station	POWER PLANT	LA006	16	106.64	52	9.91	2.82	0.16	0.49
BP WEST COAST CARSON REFINERY	REFINERY	LA030	12	48.8	3	0.49	6.05	0.01	0.51
Haynes Gen Station	POWER PLANT	LA054	20	158.83	21	5.10	19.36	0.07	0.59
Harbor Generating Station	POWER PLANT	LA030	12	48.09	4	0.55	7.08	0.01	0.60
CALIFORNIA PORTLAND CEMENT CO. M	CEMENT	SJ087	8	21.42	51	4.90	0.48	0.16	1.13
Morro Bay Power Plant, LLC	POWER PLANT	SJ012	16	98.13	113	21.73	5.93	0.35	1.15
Moss Landing	POWER PLANT	SJ012	16	122.47	241	46.19	5.15	0.75	1.72
EXXONMOBIL TORRANCE REFINERY	REFINERY	LA045	12	27.97	8	1.16	11.97	0.03	1.78
CONNACOPHILLIPS, WILMINGTON PLANT	REFINERY	LA030	12	25.65	13	1.85	11.29	0.04	1.96
Pittsburg Power Plant (CA)	POWER PLANT	SJ082	20	196.17	418	100.37	12.13	1.30	2.32
Coolwater Generating Station	POWER PLANT	SJ066	16	71.9	212	40.67	6.40	0.66	2.68
CHEVRONTEXACO EL SEGUNDO REFINERY	REFINERY	LA036	12	48.8	41	5.92	30.11	0.13	2.83
AES Alamitos	POWER PLANT	SJ016	20	205.27	472	113.30	34.79	1.46	2.88
AES Redondo Beach	POWER PLANT	SJ046	16	124.45	274	52.70	50.33	0.85	3.28
El Segundo	POWER PLANT	SJ046	16	99.49	263	50.46	40.06	0.81	3.62
Cabrillo Power I (Encina)	POWER PLANT	SJ066	16	105.88	434	83.42	17.63	1.35	3.90
Contra Costa Power Plant	POWER PLANT	SJ011	12	64.03	370	53.24	9.18	1.15	4.10
CEMEX - BLACK MOUNTAIN QUARRY	CEMENT	SJ066	12	47.86	288	41.53	7.00	0.89	4.27
MITSUBISHI CEMENT 2000, LUCERNE	CEMENT	VE002	12	26.84	230	33.12	7.38	0.71	6.32
CHEVRON RICHMOND REFINERY	REFINERY	SJ080	12	42.23	432	62.16	10.85	1.34	7.28
Duke Energy South Bay	POWER PLANT	SJ046	16	71.35	547	104.93	25.77	1.69	7.46
HANSON PERMANENTE CEMENT	CEMENT	SJ008	12	25.49	311	44.76	7.23	0.96	8.59
TESORO AVON REFINERY MARTINEZ	REFINERY	SJ082	12	31.16	424	61.04	10.08	1.31	9.61
SHELL OIL PRODUCTS, MARTINEZ	REFINERY	SJ016	12	29.9	440	63.34	11.02	1.36	10.47
CALIFORNIA PORTLAND CEMENT	CEMENT	LA006	8	11.84	98	9.40	41.68	0.30	16.82
Delta Energy Center, LLC	POWER PLANT	SJ012	6	5.43	384	27.65	8.94	1.19	30.75
Sutter Energy Center	POWER PLANT	SJ012	6	3.97	523	37.66	20.68	1.62	65.30
TXI RIVERSIDE CEMENT	CEMENT	SJ087	8	1.91	267	25.61	5.62	0.83	72.13

In this analysis, \$16/t of CO_2 was used as an assumed EOR credit value, meaning that a CO_2 source could receive \$16/t of CO_2 used for EOR. If the transportation cost from a CO_2 source to an EOR site was less than \$16/t, then the CO_2 was allocated to that EOR site instead of an alternative non-EOR sink. If the transportation costs to the closest EOR site were greater than \$16/t, then the CO_2 source should be double-checked whether to link to the EOR sink or non-EOR sink depending on the total costs.

Only four of the sources in this analysis had transportation costs to the closest EOR site that were greater than the credit value of \$16/t CO_2. A final check was run to compare final cost calculations for these sources to the alternative option of a non-EOR sink to decide which option represents the true least-cost matching. For these four sources, a new round of source-sink matching was applied with the same algorithm as before, but using the oil and gas fields without EOR potential and saline aquifers suitable for CO_2 storage in California as the sink layer instead[14]. In addition to transportation cost, sources were allocated while considering the injection costs for gas fields or saline aquifers at the second stage.

Table 19 shows the transportation and injection costs for the alternative option. The algorithm resulted in all four sources matching to saline aquifers instead of non-EOR hydrocarbon fields. The comparison of the total cost[15] to the EOR sink and non-EOR sink options confirms that the alternative options to the saline aquifers represent the true least-cost matching for three of the four sources. However, the California Portland Cement plant should remain matched to the EOR sink (LA006) since the total cost of transportation to the aquifer would be much higher than to the EOR field.

Table 19. Comparisons of alternative options for sources with EOR transportation costs over \$16/t CO_2

Facility Name	Plant Type	25-year CO_2 Flow (Mt)	Pipeline Diameter (inch)	Alternative Option			to EOR Sink	
				Destination	Transportation Cost (\$/t)	Injection Cost (\$/t)	Transportation Cost (\$/t)	EOR Credit (\$/t)
Delta Energy Center, LLC	POWER PLANT	5.43	6	Aquifer	0.00	1.95	30.75	16.00
Sutter Energy Center	POWER PLANT	3.97	6	Aquifer	0.00	2.66	65.30	16.00
TXI Riverside Cement	CEMENT	1.91	8	Aquifer	6.22	5.54	72.13	16.00
California Portland Cement	CEMENT	11.84	8	Aquifer	15.16	0.89	16.82	16.00

Appendix B presents the source-sink matching results for each of the CO_2 sources listed in this section. Thirty-three out of the 35 CO_2 sources were linked to oil fields with EOR potential, while the remaining 3 sources could find their least-cost sinks in saline aquifers.

[14] The WESTCARB database lacked sufficient detailed information to estimate the storage capacity in saline aquifers. It is assumed that the saline aquifers have enough capacity to hold all the CO_2 inflow; *i.e.*, there is no storage capacity constraint for saline aquifers.
[15] For the option "to EOR sink", total cost is calculated as transportation cost minus EOR credit (\$16/t). For the option "to non-EOR sink", total cost is calculated as the sum of transportation cost and injection cost.

In contrast to the results from the previous section, the results from the least-cost path source-sink matching provide an optimized pipeline arrangement based on construction cost criteria. In many cases this transportation distance will be longer than the straight-line distance calculated in the previous section. But, since transportation obstacle costs are included, the overall transportation cost will be less. If EOR fields were the only sequestration sinks considered, most of the sources could be linked to an appropriate sink. However, some of these sinks were more than 400 km (248 mi) away from the CO_2 source. The total transportation costs for most sources linked to EOR sinks were less than $10/t CO_2. In reality, the transportation costs might be less since in some cases sources and sinks in the same region could share pipelines or pipeline routes. This would likely decrease transportation costs below the estimates presented here.

3.6.3 CO_2 Sequestration Full-Cost Estimation

For sources matched with EOR sites, the full cost estimate included costs for capture, transportation, and an EOR credit. For sources matched with gas fields or aquifers, the full-cost estimate included capture cost, transportation cost, and injection cost.

The injection cost analysis was based on methods used by Heddle *et al.* (2003). The Heddle injection cost model requires inputs for surface injection pressure, downhole injection pressure, CO_2 flow rate, and reservoir properties. Heddle *et al.* (2003) defined a base case, a high-cost case, and a low-cost case derived from an analysis of typical data for aquifers and gas fields. Since there is no aquifer property data available in the WESTCARB data set, the reservoir properties in the base case of Heddle's spreadsheet are used in this analysis. The surface injection pressure was assumed to be 10.30 MPa. Using the spreadsheet shown in Figure 20, the injection cost was calculated using the source CO_2 flow rate. A power plant with a 25-year CO_2 emission of 67.4 Mt was used as a reference case in the spreadsheet. In this reference case, the injection cost was estimated to be $0.16 per tonne of CO_2.

Figure 21 and Appendix B show the results of the CO_2 sequestration full-cost estimation. The results of the full-cost sequestration analysis in California indicate that 20, 40, or 80 M tonnes of CO_2 per year could be sequestered in California at a cost of $31/t, $35/t, or $50/t, respectively.

		AQUIFER - Base Case			
Inputs					
Surface inj. pressure	(MPa)	**10.30**			
Downhole inj. pressure	(MPa)	**21.30**	17.08	18.25	**17.92**
CO_2 mass flow rate	(t/d)	7,389			
	(kg/s)	86			
Reservoir properties					
Reservoir pressure	(MPa)	8.4			
Thickness	(m)	171			
Depth	(m)	1239			
Permeability	(md)	22			
Temperature	(deg C)	46.0			
Viscosity calculation					
Intermediate pressure	(MPa)	14.85	12.74	13.33	13.16
Viscosity	(mPa.s)	0.050	0.042	0.044	0.044
Well number calculation					
CO_2 mobility	(md/mPa.s)	242.4	286.8	272.6	276.5
CO_2 injectivity	(t/d/m/MPa)	5.042	5.966	5.670	5.751
CO_2 injection rate per well	(t/d)	11123	8856	9555	9363
Number wells required		0.7	0.8	0.8	**0.8**
Cost calculation					
Site screening & evaluation	($M)	1.69			
Injection equipment	($M)	0.04	0.04	0.04	0.04
Well drilling cost	($M)	0.24	0.24	0.24	0.24
Total capital cost	($M)	1.97	1.97	1.97	1.97
Normal daily expenses	($M/yr)	0.01	0.01	0.01	0.01
Consumables	($M/yr)	0.02	0.02	0.02	0.02
Surface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Subsurface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Total O&M costs	($M/yr)	0.04	0.04	0.04	0.04
Annual total cost	($M)	0.34	0.34	0.34	0.34
$/tonne CO_2		0.16	0.16	0.16	**0.16**
Pressure change calculation					
CO_2 temperature	(deg C)	25			
CO_2 density	(kg/m^3)	822			
Gravity head					
Elevation change	(m)	-1239			
Pressure change	(MPa)	9.99			
Friction loss					
Well diameter	(m)	0.1200			
Viscosity	(N.s/m^2)	6.06E-05			
Reynolds number	unitless	2.26E+07	1.80E+07	1.94E+07	1.90E+07
Roughness	(ft)	0.00015			
Friction factor	unitless	0.00395	0.00395	0.00395	0.00395
Well length	(m)	1239			
Velocity	(m/s)	13.85	11.03	11.90	11.66
Pressure change	(MPa)	3.21	2.04	2.37	2.28
Downhole pressure	(MPa)	17.08	18.25	17.92	18.02

Figure 20. Injection cost estimation spreadsheet

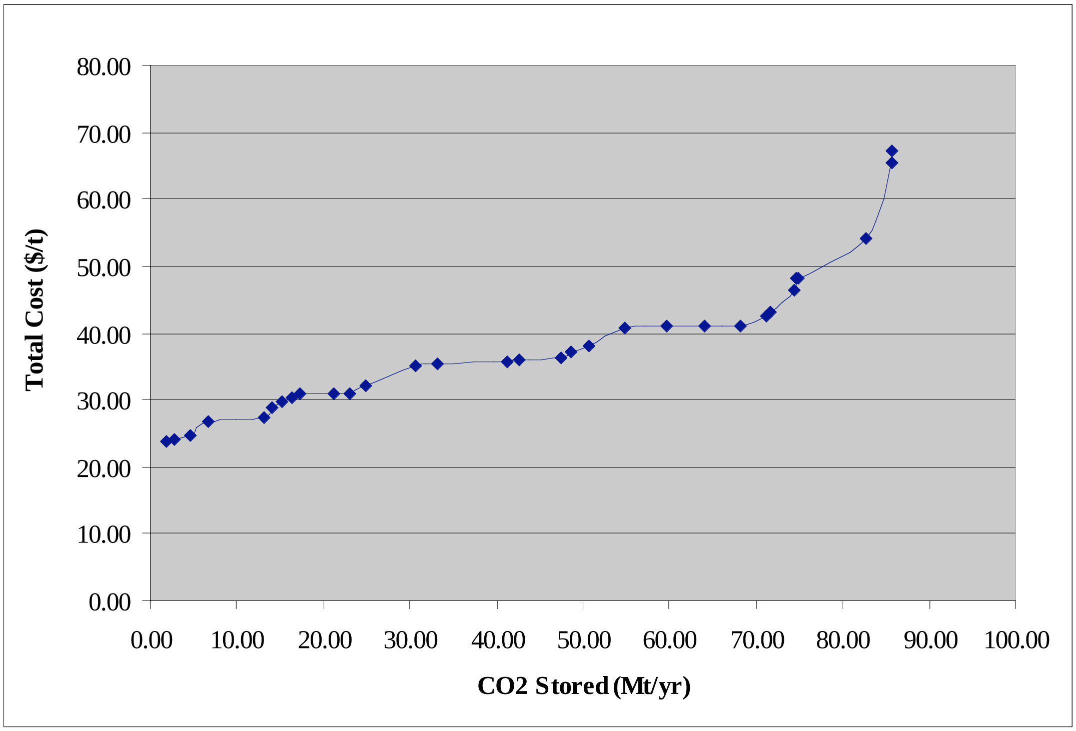


Figure 21. Marginal total cost by annual CO_2 storage rate, California

4 Conclusions

This study was conducted to highlight opportunities for carbon capture and storage in the WESTCARB region. The study provided preliminary estimates of the CO_2 emissions from major stationary sources, CO_2 storage capacity in oil and gas fields, and transportation requirements from the straight-line distance-based source-sink matching. The 77 major stationary CO_2 sources in the WESTCARB database have total annual CO_2 emissions of 159 Mt. A conservative estimation of the CO_2 storage potential in the oil and gas fields in the WESTCARB region is 5.2 Gt. The straight-line distance-based source-sink matching results showed that if all sinks, including Nevada sinks, were considered for sequestration, more than four-fifths of CO_2 sources could be matched with appropriate sinks within 50 km (31 mi). A more advanced GIS-based least-cost source-sink matching method was applied to analyze sources and sinks in California, which also takes into account the CO_2 storage capacity constraint of the sinks. For most CO_2 sources in California, the transportation costs to the corresponding EOR site are below \$10/t CO_2, less than the assumed \$16/t CO_2 credit for EOR injection. A full sequestration costing analysis, which includes capture cost, transportation cost, and injection cost (or net of EOR credit if matched to an EOR site), was also conducted for CO_2 storage in California. The results of the full sequestration cost analysis indicate that 20, 40, 80 Mt of CO_2 per year could be sequestered in California at a cost of \$31/t, \$35/t, or \$50/t, respectively.

As a preliminary approach, the study has some limitations. First, the CO_2 storage capacity in EOR sites is underestimated under the current method because of the use of cumulative oil production and gas production as proxies for original oil in place and original gas in place. Second, the study didn’t estimate the CO_2 storage capacity in coalbeds and saline aquifers due to the lack of data. Third, the transportation model and the source-sink matching algorithm can be improved by adopting updated pipeline costing data and a more comprehensive optimization approach. Finally, the least-cost source-sink matching analysis was limited to California only. Phase II studies will be targeted to address these limitations and expand the least-cost source-sink matching-based full sequestration cost to the entire WESTCARB region.

5 References

Altunin, V. V. 1975. *Thermophysical properties of carbon dioxide*. Moscow: Publishing House of Standards (in Russian).

Heddle, Gemma, Howard Herzog, and Michael Klett. 2003, *The Economics of CO_2 Storage.* MIT LFEE 2003-003 RP.

Holloway, Sam, *et al.* 1996. *The Underground Disposal of Carbon Dioxide*. Report for the JOULE II Project CT92-0031.

Reeves, Scott R. 2003. *Assessment of* CO_2 *Sequestration and ECBM Potential of U.S. Coalbeds.* U.S. Department of Energy, DE-FC26-00NT40924.

Simbeck, D. 2005. *Generic Industrial CO_2 Capture for Any Large CO_2 Flue Gas Stream*.

True, Warren R. 1998. Weather, construction inflation could squeeze North American pipelines. *Oil & Gas Journal*, 96 (35), 33-55.

Appendices

Appendix A. List of Acronyms

Abbreviation	Meaning
BPD	barrels per day
CO_2	carbon dioxide
DOE	United States Department of Energy
ECBMR	enhanced coalbed methane recovery
eGRID	Emissions and Generation Resource Integrated Database
EOR	enhanced oil recovery
ERF	ECBM recovery factor
GIS	Geographic Information System
Gt	giga metric tonnes
HV	high-volatile
HVA	high-volatile A
IGEM	Institute of Geology of Ore Deposits, Petrography, Mineralogy & Geochemistry
LFEE	Laboratory for Energy and the Environment (at MIT)
LULC	land use and land cover
LV	low-volatile
MIT	Massachusetts Institute of Technology
MMCFD	millions of cubic feet per day
Mt	million metric tonnes
MV	moderate-volatile
MWe	megawatt electrical
OGIP	original gas in place
O&M	operations and maintenance
OOIP	original oil in place
PRF	primary recovery factor
Sub	sub-bituminous
tonne	metric ton
USGS	United States Geological Survey
WESTCARB	West Coast Regional Carbon Sequestration Partnership

Appendix B. CO_2 Sequestration Full Cost Estimation, California

(1) Facility Name	(2) Plant Type	(3) Pipeline Diameter (inch)	(4) 25-year CO2 Flow (Mt)	(5) Transportation Cost ($/t)	(6) Capture Cost ($/t)	(7) EOR Credit ($/t)	(8) Injection Cost ($/t)	(9) Total Cost ($/t)
AES Alamitos	POWER PLANT	20	205.27	2.88	48.81	16.00		35.70
AES Redondo Beach	POWER PLANT	16	124.45	3.28	53.65	16.00		40.93
BP WEST COAST CARSON REFINERY	REFINERY	12	48.8	0.51	40.03	16.00		24.54
Cabrillo Power I (Encina)	POWER PLANT	16	105.88	3.90	53.11	16.00		41.00
CALIFORNIA PORTLAND CEMENT	CEMENT	8	11.84	16.82	42.20	16.00		43.02
CALIFORNIA PORTLAND CEMENT CO.M	CEMENT	8	21.42	1.13	39.05	16.00		24.18
CEMEX - BLACK MOUNTAIN QUARRY	CEMENT	12	47.86	4.27	35.45	16.00		23.72
CHEVRON RICHMOND REFINERY	REFINERY	12	42.23	7.28	40.79	16.00		32.07
CHEVRONTEXACO EL SEGUNDO REFINERY	REFINERY	12	48.8	2.83	40.03	16.00		26.86
CONNACOPHILLIPS, WILMINGTON PLANT	REFINERY	12	25.65	1.96	43.64	16.00		29.60
Contra Costa Power Plant	POWER PLANT	12	64.03	4.10	47.19	16.00		35.29
Coolwater Generating Station	POWER PLANT	16	71.9	2.68	59.58	16.00		46.26
Delta Energy Center, LLC	POWER PLANT	6	5.43	0.00	46.16		1.95	48.11
Duke Energy South Bay	POWER PLANT	16	71.35	7.46	51.03	16.00		42.49
El Segundo	POWER PLANT	16	99.49	3.62	52.98	16.00		40.60
Etiwanda Generating Station	POWER PLANT	16	106.64	0.49	56.48	16.00		40.97
EXXONMOBIL TORRANCE REFINERY	REFINERY	12	27.97	1.78	43.12	16.00		28.90
HANSON PERMANENTE CEMENT	CEMENT	12	25.49	8.59	38.21	16.00		30.80
Harbor Generating Station	POWER PLANT	12	48.09	0.60	46.35	16.00		30.95
Haynes Gen Station	POWER PLANT	20	158.83	0.59	42.86	16.00		27.45
Mandalay Generating Station	POWER PLANT	12	52.59	0.36	53.84	16.00		38.20
MITSUBISHI CEMENT 2000, LUCERNE	CEMENT	12	26.84	6.32	37.96	16.00		28.28
Morro Bay Power Plant, LLC	POWER PLANT	16	98.13	1.15	45.67	16.00		30.81
Moss Landing	POWER PLANT	16	122.47	1.72	50.70	16.00		36.42
Ormond Beach Generating Station	POWER PLANT	20	144.52	0.25	50.71	16.00		34.97
Pittsburg Power Plant (CA)	POWER PLANT	20	196.17	2.32	67.71	16.00		54.03
Scattergood Generating Station	POWER PLANT	16	74.69	0.18	81.24	16.00		65.42
SHELL OIL PRODUCTS, MARTINEZ	REFINERY	12	29.9	10.47	42.72	16.00		37.19
Sutter Energy Center	POWER PLANT	6	3.97	0.00	45.53		2.66	48.19
TESORO AVON REFINERY MARTINEZ	REFINERY	12	31.16	9.61	42.48	16.00		36.09
TXI RIVERSIDE CEMENT	CEMENT	8	1.91	6.22	55.41		5.54	67.17

Appendix C. CO_2 Capture Cost Estimation and Straight-Line Distance Source-Sink Matching for Fossil-Fuel Power Plants, WESTCARB Region

(1) Facility ORIS Code	(2) State	(3) Design Capacity (Mwe)	(4) EGRID 2000 Electricity Production (MWh)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emission (t)	(7) Estimated Annual CO2 Emission at 80% Capacity (t)	(8) Fuel Type	(9) CO2 Capture Cost ($/t CO2 Captured)	(10) CO2 Avoid Cost ($/t CO2 Avoided)	(11) Dist to Nearest EOR O&G Fields (km)	(12) Dist to Nearest Oil & Gas Fields (km)	(13) Dist to Nearest Aquifer,w / Nevada (km)	(14) Dist to Nearest Aquifer,w /o Nevada (km)	(15) Dist to Nearest Sink (km)
6288	AK	28	185,277	0.77	260,535	271,002	Coal	53.35	67.50					
8224	NV	521	4,011,243	0.88	3,998,874	3,641,547	Coal	37.84	47.87	506	403	14	227	14
126	AZ	559	1,639,965	0.34	1,455,424	3,473,565	Coal	37.53	47.48	614	614	315	315	315
6106	OR	561	3,790,921	0.77	3,998,677	4,143,170	Coal	37.52	47.46	897	668	43	43	43
2324	NV	612	4,238,122	0.79	5,343,704	5,407,923	Coal	37.13	46.98	390	382	8	55	8
6177	AZ	822	6,276,187	0.87	7,113,187	6,528,105	Coal	35.88	45.39	737	733	61	61	61
8223	AZ	850	5,876,943	0.79	6,245,526	6,327,788	Coal	35.74	45.21	744	741	91	91	91
113	AZ	1,105	6,795,289	0.70	8,441,969	9,624,591	Coal	34.66	43.84	652	649	0	0	0
3845	WA	1,460	9,400,803	0.74	10,345,031	11,259,898	Coal	33.55	42.44	1034	718	0	0	0
2341	NV	1,636	10,769,396	0.75	10,848,287	11,549,946	Coal	33.10	41.88	303	301	37	37	37
4941	AZ	2,409	18,096,243	0.86	20,137,721	18,789,569	Coal	31.64	40.03	643	641	0	0	0
10349	CA	50	349,219	0.81	177,484	176,294	GAS	79.25	100.26	124	2	0	0	0
54001	CA	74	434,076	0.67	202,072	241,425	GAS	74.47	94.21	19	9	2	2	2
54537	WA	246	1,935,850	0.90	953,258	847,812	GAS	61.86	78.26	n.a	n.a	n.a	n.a	n.a
7605	WA	248	n.a.	n.a.	804,272	n.a.	GAS	61.77	78.15	926	618	0	0	0
6559	AK	266	882,084	0.38	436,343	923,233	GAS	61.10	77.29	n.a	n.a	n.a	n.a	n.a
399	CA	293	985,252	0.38	1,024,155	2,137,553	GAS	60.19	76.14	7	0	0	0	0
96	AK	418	1,947,226	0.53	1,249,521	1,880,040	GAS	56.98	72.09	n.a	n.a	n.a	n.a	n.a
160	AZ	559	3,459,141	0.71	3,597,610	4,075,457	GAS	54.48	68.92	706	706	327	327	327
345	CA	573	2,555,413	0.51	1,486,659	2,337,514	GAS	54.27	68.65	0	0	0	0	0
8073	OR	586	2,837,242	0.55	1,725,588	2,498,589	GAS	54.08	68.42	948	628	0	0	0
141	AZ	613	2,043,449	0.38	1,333,532	2,805,220	GAS	53.70	67.94	475	475	201	201	201
54761	OR	621	4,216,100	0.77	1,674,494	1,729,179	GAS	53.60	67.81	920	705	82	82	82

Appendix C. (Continued)

(1) Facility ORIS Code	(2) State	(3) Design Capacity (Mwe)	(4) EGRID 2000 Electricity Production (MWh)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emission (t)	(7) Estimated Annual CO2 Emission at 80% Capacity (t)	(8) Fuel Type	(9) CO2 Capture Cost ($/t CO2 Captured)	(10) CO2 Avoid Cost ($/t CO2 Avoided)	(11) Dist to Nearest EOR O&G Fields (km)	(12) Dist to Nearest Oil & Gas Fields (km)	(13) Dist to Nearest Aquifer, w/ Nevada (km)	(14) Dist to Nearest Aquifer, w/o Nevada (km)	(15) Dist to Nearest Sink (km)
55077	NV	632	2,102,946	0.38	857,735	1,806,708	GAS	53.46	67.63	331	329	3	53	3
228	CA	676	2,769,971	0.47	1,664,108	2,845,844	GAS	52.90	66.93	6	3	0	0	0
329	CA	727	2,634,295	0.41	1,652,392	3,195,343	GAS	52.31	66.18	129	127	68	68	68
310	CA	729	2,276,565	0.36	1,413,186	3,171,246	GAS	52.29	66.15	103	103	95	95	95
2322	NV	790	3,691,787	0.53	2,033,845	3,049,814	GAS	51.64	65.33	335	333	0	60	0
404	CA	823	1,830,310	0.25	1,053,156	3,319,639	GAS	51.32	64.92	5	1	0	0	0
302	CA	1,000	3,226,385	0.37	2,165,749	4,705,593	GAS	49.79	62.99	41	41	34	34	34
331	CA	1,049	2,631,760	0.29	1,696,714	4,739,425	GAS	49.43	62.53	22	21	16	16	16
259	CA	1,056	5,262,644	0.57	3,101,024	4,361,496	GAS	49.38	62.46	73	30	25	25	25
356	CA	1,303	3,273,678	0.29	1,983,637	5,531,230	GAS	47.80	60.47	6	0	0	0	0
260	CA	1,404	8,048,763	0.65	4,452,297	5,442,906	GAS	47.25	59.77	133	23	1	1	1
350	CA	1,500	4,002,319	0.30	2,445,546	6,422,971	GAS	46.77	59.17	5	5	0	0	0
400	CA	1,606	3,568,531	0.25	2,238,622	7,059,115	GAS	46.28	58.55	23	19	7	7	7
271	CA	1,984	6,838,839	0.39	4,288,462	8,718,601	GAS	44.79	56.66	141	3	0	0	0
315	CA	2,129	6,473,582	0.35	3,957,192	9,123,209	GAS	44.30	56.05	1	1	0	0	0
2336	NV	413	1,793,661	0.50	1,683,565	2,714,333	GAS	57.10	72.23	261	185	0	157	0
330	CA	996	2,285,397	0.26	1,447,083	4,421,948	GAS	49.82	63.03	5	1	0	0	0
79	AK	23	67	0.00	45	121,229	Oil	66.15	78.63	n.a	n.a	n.a	n.a	n.a
6286	AK	40	3,054	0.01	6,537	608,060	Oil	61.53	73.14	n.a	n.a	n.a	n.a	n.a
6285	AK	129	335,913	0.30	335,613	906,143	Oil	52.92	62.90	n.a	n.a	n.a	n.a	n.a

Note: All sources in Alaska are not matched.

Appendix D. CO_2 Capture Cost Estimation and Straight-Line Distance Source-Sink Matching for Refineries, WESTCARB Region

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (BPD)	(5) Estimated Annual CO2 Emission (t)	(6) CO2 Capture Cost ($/t CO2 Captured)	(7) CO2 Avoid Cost ($/t CO2 Avoided)	(8) Dist to Nearest EOR O&G Fields (km)	(9) Dist to Nearest Oil & Gas Fields (km)	(10) Dist to Nearest Aquifer, w/ Nevada (km)	(11) Dist to Nearest Aquifer, w/o Nevada (km)
12	PETRO STAR VALDEZ	AK	46,000	390,000	51.12	64.67	n.a.	n.a.	n.a.	n.a.
13	TESORO ALASKA PETROLEUM CO KENAI	AK	72,000	601,000	47.86	60.55	n.a.	n.a.	n.a.	n.a.
9	TESORO NORTHWEST, ANACORTES	WA	110,000	959,000	44.71	56.57	1244	930	16	16
10	CONNA COPHILLIPS, WILMINGTON PLANT	CA	131,000	1,140,000	43.64	55.21	9	0	0	0
6	PUGET SOUND REFINING CO. ANACORTES	WA	145,000	1,210,000	43.28	54.75	1245	932	19	19
5	EXXONMOBIL TORRANCE REFINERY	CA	149,000	1,243,000	43.12	54.55	5	1	0	0
7	SHELL OIL PRODUCTS, MARTINEZ	CA	160,000	1,329,000	42.72	54.05	29	6	5	5
8	TESORO AVON REFINERY MARTINEZ	CA	166,000	1,385,000	42.48	53.75	25	1	1	1
11	FLINT HILLS NORTH POLE	AK	197,000	1,651,000	41.49	52.49	n.a.	n.a.	n.a.	n.a.
1	BP, CHERRY POINT	WA	223,000	1,877,000	40.79	51.60	1288	972	0	0
3	CHEVRON RICHMOND REFINERY	CA	225,000	1,877,000	40.79	51.60	50	29	5	5
2	BP WEST COAST CARSON REFINERY	CA	260,000	2,169,000	40.03	50.64	3	1	0	0
4	CHEVRONTEXACO EL SEGUNDO REFINERY	CA	260,000	2,169,000	40.03	50.64	3	1	0	0

Note: It is assumed that the flue gas comprises of 10% of CO2 and 90% of N2 in volume.
Refineries at Alaska are not matched to corresponding Sinks

Appendix E. CO_2 Capture Cost Estimation and Straight-Line Distance Source-Sink Matching for Cement Plants, WESTCARB Region

(1) ID	(2) Plant Name	(3) State	(4) Annual Cement Production (kt)	(5) Estimated Annual CO2 Emission (t)	(6) CO2 Capture Cost ($/t CO2 Captured)	(7) CO2 Avoid Cost ($/t CO2 Avoided)	(8) Dist to Nearest EOR O&G Fields (km)	(9) Dist to Nearest Oil & Gas Fields (km)	(10) Dist to Nearest Aquifer, w/ Nevada (km)	(11) Dist to Nearest Aquifer, w/o Nevada (km)
16	TXI RIVERSIDE CEMENT	CA	94	85,000	55.41	70.09	182	180	23	23
12	LAFARGE NORTH AMERICA, SEATTLE	WA	329	298,000	45.69	57.80	1117	818	0	0
14	CLARKDALE PLANT, PHOENIX CEMENT	AZ	469	424,000	43.47	54.99	490	486	105	105
2	ASH GROVE CEMENT, SEATTLE PLANT	WA	526	476,000	42.78	54.12	1117	818	0	0
4	CALIFORNIA PORTLAND CEMENT	CA	581	526,000	43.47	54.99	71	68	64	64
8	ASH GROVE CEMENT COMPANY DURKEE,	OR	660	597,000	41.49	52.48	851	657	28	28
3	CALIFORNIA PORTLAND CEMENT CO. M	CA	1052	952,000	39.05	49.40	46	38	31	31
1	RILLITO CEMENT PLANT ARIZONA POR	AZ	1105	1,000,000	38.81	49.09	536	536	298	298
11	HANSON PERMANENTE CEMENT	CA	1253	1,133,000	38.21	48.33	87	24	19	19
13	MITSUBISHI CEMENT 2000, LUCERNE	CA	1319	1,193,000	37.96	48.03	161	159	15	15
5	CEMEX - BLACK MOUNTAIN QUARRY	CA	2351	2,127,000	35.45	44.85	182	180	23	23

Note: It is assumed that the flue gas comprises of 25% of CO2 and 75% of N2 in volume.