Technical Memorandum:
Economic Benefit Evaluation of
CO_2 EOR Development in Texas

Submitted to:

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1.0 Introduction

In 1983 and 1996, the Bureau of Economic Geology at the University of Texas at Austin (BEG) and the U.S. Department of Energy (DOE), respectively, identified 131 nearly depleted oil reservoirs or fields along the Texas Gulf Coast region with an estimated 2.3 billion barrels of recoverable reserves as potential candidates for implementation of a fieldwide enhanced oil recovery operation (EOR) involving the injection of carbon dioxide (CO_2). More than 30 years later, only two of the 131 fields identified by BEG and DOE have been redeveloped. These two fields are currently operated by Denbury Onshore, LLC, a wholly owned subsidiary of Denbury Resources Inc. (Denbury Onshore) and represent a mere 9 percent of the 2.3 billion barrels of recoverable reserves identified by the BEG and DOE.

One can speculate on the myriad of reasons for the absence of any significant CO_2 based fieldwide recovery operations occurring since these reports, but there is no question that the lack of a statutory unitization framework plays a significant role in this void. These fields are located in Texas, the only major oil and gas producing state with no statutory unitization procedure assisting operators in binding all owners, possibly hundreds and even thousands of such owners, to the operation of such fields as one large unitized lease. As a result, only in Texas is CO_2 EOR production of older, nearly depleted fields limited by the requirement to have 100 percent of the working, mineral and royalty interest owners' ratifications of the unit. Without such statutory framework, many of these fields will not benefit from any CO_2 based EOR operation, which is identified by the industry as one of the most efficient methods of extracting the remaining recoverable oil from a nearly depleted oil reservoir. As a result, these fields will eventually deplete; the leases will expire; and the field will be permanently abandoned, leaving hundreds of millions of barrels of oil unrecovered.

Louis Berger, in collaboration with Denbury Onshore, evaluated the potential economic benefits of increasing tertiary CO_2 EOR along the Gulf Coast region of Texas. In particular this study discusses:

- development phases of an oil field from exploration to tertiary CO_2 EOR;
- the necessity of statutory unitization in Texas for EOR projects;
- two of Denbury Onshore's CO_2 EOR success stories as case studies; and
- potential economic benefits of increasing CO_2 EOR operations under four development scenarios.

The economic analyses determined that even if statutory unitization encouraged only 10 percent of the remaining nearly depleted fields to be developed utilizing CO_2 EOR, the economic benefits to the Texas Gulf Coast region would be significant.

1.1 Development Phases of an Oil Field

No understanding of EOR operations and the need for unitization can be had without an understanding of the traditional phases of a field from the drilling of the first exploratory well through full field development and eventually enhanced oil recovery operations. These development phases of an oil field are generally referred to as primary, secondary, or tertiary phases of recovery.

On average, primary production usually accounts for approximately 20 percent of a reservoir's original oil in place (OOIP). Secondary production produces on average an additional 10 to 20 percent of the OOIP, and tertiary production generally results in an additional 10 to 20 percent recovery of the OOIP. These primary, secondary and tertiary production techniques cumulatively can result in the recovery of 40 to 60 percent of a reservoir's OOIP.

At the exploratory stage of a field, the operator drills an exploratory well within the area of interest. Presuming that this well is drilled and successfully completed, the operator will continue to drill and complete additional wells in order to define the extent of the oil field. Once the field limits are identified, in order to efficiently produce and recover the oil during these various phases, the operator studies the physical characteristics of the underlying reservoir. From a reservoir standpoint, primary recovery typically relies on natural reservoir pressures to bring the oil to the surface towards the well bores where it is produced.

After the operator has produced the oil during the primary phase using the natural pressure of the oil reservoir, all production will cease and the field will be abandoned. At this stage, an operator must implement some type of method to increase and maintain the reservoir pressure in order to extract the oil. Through secondary recovery techniques, operators inject water or gas to displace oil and drive it to producing wells. Again, once such secondary operations cease to produce oil at an economical rate, the field will be abandoned unless a third or tertiary form of recovery operations is implemented.

At the tertiary phase of development, the operator implements a method of recovery beyond the primary and secondary forms of oil recovery. During tertiary production, various methods of recovery can be implemented, including the injection of CO_2 in order to increase the reservoir pressure and produce additional recoverable oil. Through CO_2 EOR, operators inject CO_2 into the reservoir where the CO_2 flows completely through the reservoir mixing with the oil to reduce its viscosity and causing the oil to swell slightly and detach from the adjoining rock and join with the injected CO_2 to be carried to the producing wells.

1.2 Fieldwide Unitization Evaluation Stage for CO_2 EOR Operations

At the tertiary stage of oil development, in order to maximize the oil recovery rate from the field, the entire oil reservoir must be unitized (consolidated from an operator's standpoint) and operated as one lease by one operator. Unfortunately, in most cases, the oil reservoir ignores oil and gas lease boundaries and consequently, multiple tracts and leases operated by multiple operators must be combined as one tract in order to effectively operate the oil reservoir as one lease. The benefit of this approach is to allow one operator to place the necessary injection and production wells strategically without the artificial limitations caused by the individual lease boundaries. With the exception of Texas, all major oil and gas producing states recognize the need for a statutory unitization framework in order to assist the appointed unit operator in gaining fieldwide approval of all owners of production so that the field can be operated as one lease. This process is easier said than done even with the existence of a statutory unitization framework. Experience has shown that regardless of the availability of statutory unitization, the unitization process takes between 4 to 9 years to reach a contractual agreement among, in some cases, thousands of owners.

When the field has reached this nearly depleted development stage and the operators within the field agree to implement fieldwide operations, the parties must evaluate and agree upon the boundaries of the field; how each of their lands, leases and wells will participate in the unit; how revenue and costs will be shared; and how one operator will be selected to operate the field in which there may be many individual operators within the field's boundary. This initial evaluation process can be contentious; can take years; and result in significant expenses being incurred in order to define the field and reach these contractual agreements.

Assuming these agreements are eventually reached and the field boundary is defined and agreed upon, the royalty, mineral and working interest owners within the field must then be identified and confirmed through a title review of the county records. Because these fields have been typically operated for years, it is common to have thousands of owners spanning multiple generations, in just one field. Additionally, lost heirs must be accounted for. Further, the geographical extent of a field alone—some fields covering thousands of acres such as the 20,000 acre Conroe Field—also results in the number of owners to be extensive. The regulatory scheme, regardless of whether it is voluntary or statutory, requires that each owner—royalty, mineral, working interest owners, be afforded an opportunity to participate in the proposed fieldwide unit. This title review process alone costs millions of dollars in expenses and takes years to complete. Upon identifying the owners within the field and reaching the necessary agreements to operate the field as one lease, each owner is then provided an opportunity to ratify the proposed fieldwide unit.

1.3 Impact of a Non-consenting Minority Interest Owner under a Voluntary Unitization Framework

Currently, all major oil producing states except for Texas have adopted a form of statutory unitization procedure. Although the Texas State Legislature has evaluated proposals for establishing a statutory unitization process, such proposals have been unsuccessful to date. However, in order to support the development of EOR projects in the state of Texas, and reap the estimated economic benefits of such projects as described in this study, such statutory unitization is necessary.

In the event that there are non-consenting owners to the proposed unitization and in all probability there will be, the existing Texas voluntary unitization framework does not allow for the elected unit operator to include the remaining non-consenting owners and operators in the fieldwide unit. As result, without the joinder of these non-consenting owners, the operator is precluded from operating the field as one large lease or reservoir. Although many states statutorily provide that once an operator obtains a certain statutory percentage of approvals, the remaining non-consenting owners become part of the proposed fieldwide unit. Texas does not provide for such authority. Consequently, because unitization in Texas is voluntary, a single entity, regardless of its ownership percentage, can override the interests of all majority consenting owners. After years of negotiating and incurring a significant amount of expenditures, it is possible that one owner or owners representing a minority interest can preclude the majority owners within a field who have agreed to the fieldwide unit from implementing such unit operations.

At the tertiary phase of oil recovery in a nearly depleted oil field, the capital and operating costs are extraordinary. The construction of a recycling facility for the CO_2, the injection wells and CO_2 lines and numerous other developmental expenses can result in such expenditures exceeding over $200 million.

While CO_2 EOR operations are possible through the voluntary unitization process, the uncertainty of success due to potential hold-out interest owners; the extraordinary upfront capital investments necessary for CO_2 EOR and the additional costs incurred solely as a consequence of these nonconsenting owners, make these EOR operations efforts in these identified fields economically impractical in most cases without some legislative framework allowing for statutory unitization.

1.4 The Need for Statutory Unitization due to CO_2 Characteristics

The existence of a statutory unitization framework is critical for CO_2 EOR, especially those utilizing industrial or anthropogenic CO_2. Because the CO_2 injected into the reservoir through CO_2 EOR operations flows through the entire reservoir, it affects all ownership interests with respect to the reservoir. Likewise, due to these physical characteristics of CO_2, it is imperative that the unit operator is able to contain the CO_2 within the reservoir to maintain the pressure in order to efficiently produce the oil from the nearly depleted reservoir. Therefore, to strategically develop the entirety of the oil reservoir and maintain the pressure of the reservoir in order to achieve the most efficient CO_2 flood, the operator must control the entirety of the field, an authority that is not guaranteed in a voluntary unitization framework.

Currently, CO_2 EOR projects are, or will be, utilizing industrial CO_2 in its operations. Increasing state and federal regulatory requirements to manage industrial CO_2 make utilization of industrial CO_2 in nearly depleted oil fields more attractive. In order to utilize industrial CO_2, the operator is subject to increasing state and federal environmental trends and requirements to monitor and verify that the industrial CO_2 is injected underground and remains trapped there permanently. Without statutory unitization or total control over the reservoir by some other means, which would allow the operator to monitor and comply with these environmental regulations over the entirety of the oil field, the operator would be limited to only those ratified or consenting portions of the unit, and thus, would be precluded from utilizing the industrial CO_2.

In short, Texas needs to replace its antiquated system of voluntary unitization with a statutory unitization framework for nearly depleted oilfields to be successful in attracting the large volumes of CO_2 needed for CO_2 EOR projects cited by the DOE and BEG that could be supplied by industrial sources from the Texas Gulf Coast region.

1.5 Impact of Voluntary Unitization in Texas and Current Attempts to Implement Legislation

There are far more examples of fields where companies could not proceed with efficient tertiary development because of a lack of full field unitization, resulting unfortunately, in much higher costs to produce from multiple partially unitized and non-unitized fields. One such example is the West Texas Slaughter Field. This 87,000-acre field includes 25 unitized areas and 28 non-unitized areas used for secondary production. To ensure these areas remained separated and in compliance with the voluntary unitization state regulations, multiple operators drilled an additional 427 offset wells at a cost of $157 million that did not improve productivity in terms of ultimate recovery (Weaver, 1986).

Proposals introduced in recent sessions of the Texas Legislature to address the issue of statutory unitization would establish a legal framework for developing a plan of unitization that would only take effect after the approval of a super majority (e.g., at least 70 percent of the aggregate working interests and royalty interests). To date, passage of these bills has been unsuccessful.

2.0 EOR Success Stories-Oyster Bayou Field Unit and West Hastings Unit Case Studies

With that said, however, the only two examples of successful CO_2 EOR projects in the Gulf Coast region of Texas implemented since the BEG and DOE reports are included here as case studies: Oyster Bayou Field and West Hastings Field. While in both cases, these fields were unitized under the voluntary system, developmental issues persisted. In the case of Oyster Bayou, the project was nearly abandoned despite having a strong ratification (more than 75 percent) of the unit at the outset. A holdout interest owner, whose parcels were crucial to the project succeeding came close to not ratifying the agreement. Had that occurred, the field where production had slipped to fewer than 100 barrels per day would have been plugged and abandoned. Today, the field produces close to 6,000 barrels of oil per day (BOPD). For West Hastings Field, which was unitized many years ago, redevelopment occurred in a more orderly fashion.

2.1 Oyster Bayou Field

The Oyster Bayou Field Unit is located in Chambers County, Texas, east of Galveston Bay. The field was discovered in 1941 and had a cumulative production of 143 million barrels prior to CO_2 EOR. Peak production occurred in 1977 with an average daily production of 19,600 barrels. Production levels at the time Denbury Onshore acquired the majority interest in the field in 2007 had fallen to fewer than 100 barrels of oil per day (BOPD) (Figure 1). Denbury Onshore achieved unitization of the field in 2010, and CO_2 injection was initiated soon after. Currently, Oyster Bayou field averages close to 6,000 BOPD compared to fewer than 100 BOPD prior to the start of CO_2 injection (Figure 2). Because of the geological and reservoir characteristics of this 3,912 acre field, Denbury Onshore developed it in one stage. Production commenced in December 2011 with initial proven tertiary reserves of 14.1 million barrels in 2011.

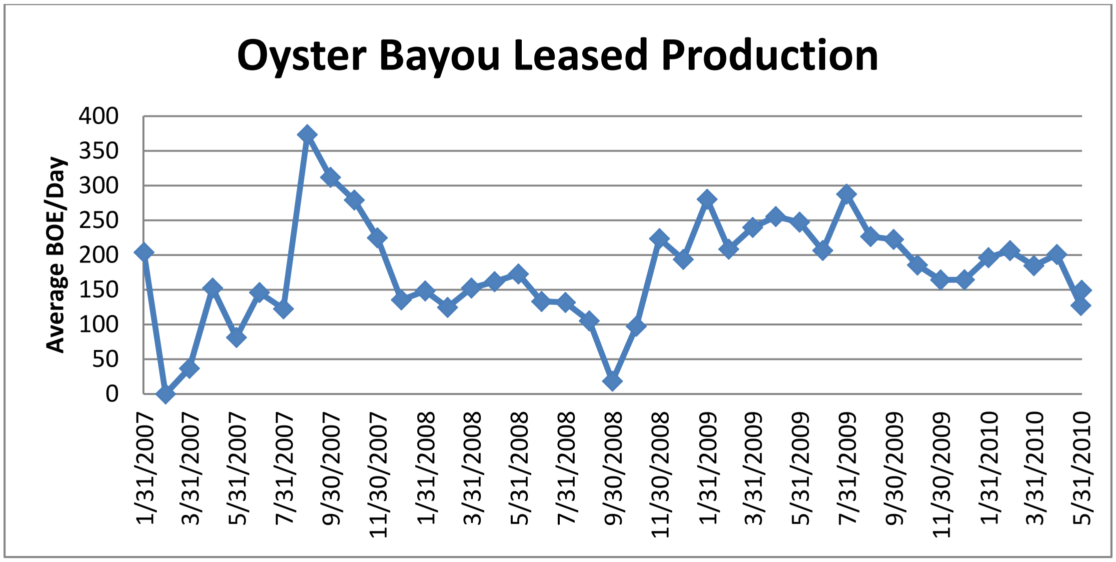

Figure 1. Non-Unitized Average Monthly Production

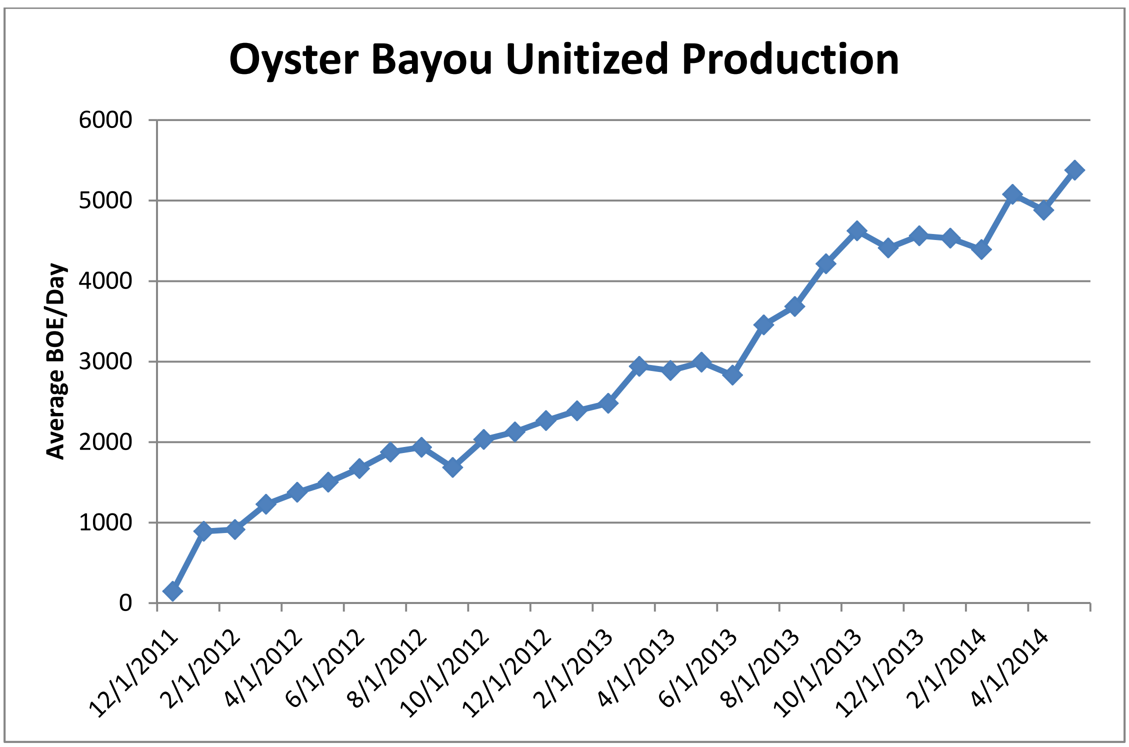

Figure 2. Unitized Average Monthly Production

The cost to prepare the Oyster Bayou Field Unit for CO_2 EOR is summarized in Table 1. Denbury Onshore estimated a 27-year life for the field. Field development took approximately 4 years.

Table 1. Estimated Capital Costs for Oyster Bayou Field Unit EOR Project

Project Component	Capital Costs (Millions)
Well work	$43.7
Field infrastructure	$14.9
Land	$.9
Recycling facility and power	$105.8
Total	$165.3

Source: Denbury Onshore 2010

The redevelopment of the Oyster Bayou Field has and will continue to provide an economic benefit to the region and state. Capital investments of $165.3 million over 4 years were estimated to provide 1,199 jobs—an average of 300 jobs per year during the construction and development activity for the Houston metropolitan area. The capital investments were estimated to bring $138 million in gross regional product and $219 million in sales to the Houston-Sugar Land-Baytown Metropolitan Statistical Area (Table 2).

Across Texas, these capital investments resulted in a slightly higher local capture of the direct investments and considerably higher secondary effects because additional economic activity was generated in the larger Texas economy. The redevelopment of the field supported an estimated 390 average annual jobs, $98 million in labor income, $147 million gross state production, and $249 million in sales over the 4-year period in Texas (Table 2).

Table 2. Economic Benefits of Capital Investments in Oyster Bayou Field in 2013

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Houston-Sugar Land-Baytown Metropolitan Statistical Area				
Direct impacts	601 (150)	$60.1	$75.5	$117.5
Secondary impacts	598 (150)	$37.2	$62.4	$101.2
Total	1,199 (300)	$97.3	$137.9	$218.7
Texas				
Direct impacts	773 (193)	$55.1	$72.0	$121.6
Secondary impacts	787 (197)	$43.2	$74.7	$127.1
Total	1,560 (390)	$98.3	$146.7	$248.7

Note: Values are in 2012 dollars

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

In addition, increased production benefited Chambers County through the generation of ad valorem taxes. In 2012, Denbury Onshore paid $3.0 million in ad valorem taxes associated with the Oyster Bayou field. In addition, private mineral owners received production royalties.

In 2013, production from the wells in the Oyster Bayou Field Unit totaled approximately 1.2 million barrels, an average of 3,409 BOPD, yielding a value of $134.5 million. These revenues (less payments for taxes and royalties) supported 492 jobs, $164 million in sales, and $114 million in gross domestic product in the Houston-Sugar Land-Baytown Metropolitan Statistical Area (Table 3). Across the state, there were higher secondary effects because additional economic activity was captured within the larger Texas economy, resulting in 581 jobs, $51 million in labor income, $118 million in gross state product, and $175 million in sales in 2013 (Table 3).

Table 3. Economic Benefits of Production Revenues from Oyster Bayou Field in 2013

Economic Impact Type	Jobs	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Houston-Sugar Land - Baytown Metropolitan Statistical Area				
Direct impacts	201	$34.2	$81.9	$113.3
Secondary impacts	291	$19.5	$32.0	$50.8
Total	492	$53.7	$113.9	$164.1
Texas				
Direct impacts	214	$29.5	$80.2	$113.3
Secondary impacts	367	$21.1	$37.7	$62.0
Total	581	$50.6	$117.9	$175.3

Note: Values are in 2012 dollars

2.2 West Hastings Field

The Hastings Field is located just south of Houston in Brazoria and Galveston Counties, Texas and was discovered in 1934 by Stanolind Oil Company. The Hastings Field is divided into East Hastings Field and West Hastings Field. In 1985, the West Hastings Unit was approved by the Railroad Commission of Texas as a secondary recovery unit. Denbury Onshore initially acquired a majority interest in the West Hastings Unit in 2009. Production from CO_2 EOR operations commenced in January 2012 with initial proven tertiary reserves of 46.2 million barrels from the West Hastings Unit. Prior to the start of CO_2 injection, the West Hastings Unit was producing 1,873 BOPD and 1,825 mcfd. In 2013, the West Hastings Unit was producing 669 BOPD conventionally and 4,874 BOPD with CO_2 injection in the first phase.

Louis Berger staff used data provided by Denbury Onshore to estimate the economic benefits of developing the West Hastings Unit for CO_2 EOR. All dollar figures are presented in 2014 dollars unless otherwise noted below. The capital costs to develop the field between 2009 and 2013 were estimated to be approximately $300 million (Table 4).

Table 4. Estimated Capital Costs for West Hastings Unit EOR Project, 2009–2013

Project Component	Capital Costs (Millions)
Well work	$68.5
Field infrastructure	$22.8
Land	$1.6
Recycling facility and power	$207.0
Total	$299.9

Source: Denbury Onshore

The redevelopment of the West Hastings Unit has provided economic benefits to the region and state. Capital investments of $300 million over the past 5 years were estimated to provide 1,726 total annual jobs in the Houston-Sugar Land-Baytown Metropolitan Statistical Area, an average of 345 jobs per year during the redevelopment phase. The capital investments were estimated to bring $194 million in gross regional product and $308 million in sales to the Houston-Sugar Land-Baytown Metropolitan Statistical Area over the 5-year period.

Across Texas, these capital investments resulted in a slightly higher local capture of the direct investments and considerably higher secondary effects because additional economic activity was generated in the larger Texas economy. Approximately 517 average annual jobs, $164 million in labor income, $249 million gross state production, and $436 million in sales were supported by the capital investments in the West Hastings Field over the 5-year period in Texas (Table 5).

Table 5. Economic Benefits of Capital Investments in West Hastings Field, 2009–2013

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Houston-Sugar Land-Baytown Metropolitan Statistical Area				
Direct impacts	1,128 (226)	$107.7	$131.8	$206.7
Secondary impacts	598 (120)	$37.2	$62.4	$101.2
Total	1,726 (345)	$144.9	$194.2	$307.9
Texas				
Direct impacts	1,141 (228)	$84.9	$112.7	$203.0
Secondary impacts	1,441 (288)	$78.9	$136.7	$233.0
Total	2,583 (517)	$163.8	$249.4	$436.0

Note: Values are in 2012 dollars

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

Increased production benefited Brazoria and Galveston Counties through the generation of ad valorem taxes. In 2013, Denbury Onshore paid approximately $7.4 million in ad valorem taxes associated with the West Hastings Unit. In addition, private mineral owners benefited from production royalties. In 2013, CO_2 EOR production from the wells in the West Hastings Unit was 5,543 barrels per day or 2.0 million barrels per year, yielding a value of $219.9 million. These revenues (less payments for taxes and royalties) supported 792 jobs, $265 million in sales, and $184 million in gross regional product in the Houston metropolitan area. Across the state, there were higher secondary effects because additional economic activity was captured within the larger Texas economy, resulting in 937 jobs, $82 million in labor income, $190 million in gross state product, and $283 million in sales in 2013 (Table 6).

Table 6. Economic Benefits of Production Revenues from West Hastings Field in 2013

Economic Impact Type	Jobs	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Houston-Sugar Land-Baytown Metropolitan Statistical Area				
Direct impacts	323	$55.1	$132.0	$182.6
Secondary impacts	469	$31.4	$51.6	$82.0
Total	792	$86.5	$183.6	$264.6
Texas				
Direct impacts	345	$47.6	$129.3	$182.6
Secondary impacts	592	$34.1	$60.8	$100.0
Total	937	$81.7	$190.1	$282.6

Note: Values are in 2012 dollars

3.0 Economic Benefits of Increased CO_2 EOR along the Texas Gulf Coast

Utilizing the economic data of Oyster Bayou Field Unit and West Hastings Unit, Louis Berger applied these case studies to estimate the potential economic benefits of extending CO_2 EOR production to other areas along the Gulf Coast of Texas as if a statutory unitization framework were in place in the state of Texas that would encourage the implementation of CO_2 EOR. Given the uncertainty of future development, the economic potential of EOR was estimated under four development scenarios discussed below. Note that these four development scenarios are not based on publicly announced or privately developed investment plans. The methodology and assumptions used in evaluating the economic benefits are discussed in detail in the appendix.

The study examined the positive impact the passage of some form of statutory unitization in Texas would have to encourage the tertiary development of these fields identified by the BEG and DOE. This study examined the Denbury Onshore operated Oyster Bayou Field Unit and West Hastings Unit and then utilized those to arrive at the total development costs that would be needed to expand CO_2 EOR to other candidate fields in the Gulf Coast region. Finally, information and data available on candidate fields, such as remaining reserves, and CO_2 EOR potential, were used to estimate potential production if these fields were further developed. The analysis focused on the economic potential of CO_2 EOR within the region of Railroad Commission of Texas (RRC) Districts 2, 3, and 4.

To evaluate the economic benefits of increasing oil production using CO_2 EOR, Louis Berger staff evaluated the potential in the three RRC Districts that cover much of the Texas Gulf Coast. Using data published by the BEG and the DOE, and assuming a 17 percent recovery factor, an estimated 2.3 billion barrels of recoverable reserves with high EOR potential exist within RRC Districts 2, 3, and 4. Louis Berger staff estimated the potential economic benefits if these fields were redeveloped using CO_2 EOR techniques under four different development scenarios each of which are defined below: Full Build-out Scenario; a 30 Percent Scenario; a 20 Percent Scenario, and a 10 Percent Scenario. Note that these four development scenarios were not based on publicly announced or privately developed investment plans.

3.1 Full Build-out Scenario

The term "Full Build-out Scenario" for purposes of this evaluation means the estimated economic benefits if 100 percent of the total number of fields identified by BEG and DOE in RRC Districts 2, 3, and 4 were fully developed for EOR operations. Table 7 summarizes the development and production assumptions used to estimate the state benefits with the Full Build-out Scenario in the Texas Gulf Coast region.

Table 7. Development and Production Assumptions for Full Build-out Scenario

Project Component	Information
Counties with potential production	36 counties
Number of fields developed	129 fields (excludes Oyster Bayou and West Hastings)
Development activity	2015–2039 (25 years)
Total development costs (2014$)	$28.5 billion
Production activity	2019–2072 (54 years)*
Oil production	2112.4 million barrels
Value of production (2014$)	$227.6 billion
Ad valorem taxes (2014$)	$22.8 billion
Severance taxes (2014$)	$8.9 billion
Private production royalties (2014$)	$37.9 billion

Source: Denbury Onshore and Louis Berger analysis

*Based on average production curves.

Capital investments of $28.5 billion over 25 years would provide an estimated 10,588 average annual jobs during the construction and development phases, and bring $47 billion in sales and $27 billion in gross regional product to the state of Texas over the 25-year period (Table 8). Across the state, the secondary impacts generated by the development and production of EOR would be larger than those within the individual RRC Districts because additional economic activity would be captured in the larger Texas economy. In addition, production revenues would benefit the state, supporting jobs, income, and sales, as well as generating ad valorem and severance taxes and private production royalties. These revenues (less payments for taxes and royalties) would support an estimated 14,758 average annual jobs, $241 billion in sales, and $162 billion in gross regional product over the 54-year period (Table 8).

Table 8. State Economic Benefits of Development and Production in RRC Districts 2, 3, and 4

Economic Impact Type	Jobs (Average Annual Jobs)	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Development Impacts, 2015–2039, Development Costs of $28.5 Billion				
Direct impacts	120,813 (4,833)	$9,576.3	$13,220.7	$23,359.5
Secondary impacts	143,887 (5,755)	$8,014.6	$13,771.7	$23,586.3
Total	264,700 (10,588)	$17,590.9	26,992.4	46,945.8
Production Impacts, 2019–2072, Net Production Revenues of $158.0 Billion				
Direct impacts	293,231 (5,430)	$40,534.9	$110,052.3	$155,415.7
Secondary impacts	503,694 (9,328)	$29,002.3	$51,706.9	$85,101.3
Total	796,925 (14,758)	$69,537.2	$161,759.2	$240,517.0

Note: Values are in 2014 dollars

3.2 30 Percent Scenario

Because the possibility exists that a certain number of fields would not be redeveloped using CO_2 EOR, three additional scenarios were developed to evaluate a lower level of development. The first additional scenario is the "30 Percent Scenario" and is defined as the estimated economic benefits if only 30 percent of the total potential reserves were fully developed within 16 fields for fieldwide CO_2 EOR. Relatively larger fields in each RRC District were selected for full field development to represent the 30 Percent Scenario. Table 9 summarizes the development and production information for the 30 Percent Scenario. Note that this development scenario was not based on publicly announced or privately developed investment plans.

Table 9. Development and Production Assumptions for the 30 Percent Scenario

Project Component	Information
Counties with production	Sample counties in RRC Districts 2, 3, and 4
Number of fields developed	16 fields
Development activity	2015–2039 (25 years)
Total development costs (2014$)	$8,498.4 million
Production activity	2019–2072 (54 years)*
Oil production	629.51 million barrels
Value of production (2014$)	$67,683 million
Ad valorem taxes (2014$)	$7,062 million
Severance taxes (2014$)	$2,671 million
Private production royalties (2014$)	$11,281 million

Source: Denbury Onshore and Louis Berger analysis; *Based on average production curves.

Table 10 summarizes the economic benefits of the 30 Percent Scenario.

Table 10. Economic Benefits of the 30 Percent Scenario

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
RRC Districts 2, 3, and 4				
Development Impacts, 2015–2039, Development Costs of $8.5 Billion				
Direct impacts	35,070 (1,403)	$2,896.2	$3,913.3	$6,779.0
Secondary impacts	29,016 (1,161)	$1,569.6	$2,744.5	$4,488.1
Total	64,086 (2,564)	$4,465.8	$6,657.8	$11,267.1
Production Impacts, 2019–2072, Net Production Revenues of $46.7 Billion				
Direct impacts	91,544 (1,695)	$10,965.1	$32,597.8	$46,668.6
Secondary impacts	106,109 (1,965)	$6,076.6	$10,426.1	$16,971.9
Total	197,653 (3,660)	$17,041.7	$43,023.9	$63,640.5

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

3.3 20 Percent Scenario

The "20 Percent Scenario" is defined as the estimated economic benefits if 20 percent of the total potential reserves were fully developed for fieldwide CO_2 EOR within 6 fields. Table 11 summarizes the development and production assumptions for this 20 Percent Scenario. Note that this development scenario was not based on publicly announced or privately developed investment plans.

Table 11. Development and Production Assumptions for the 20 Percent Scenario

Project Component	Information
Counties with production	Sample counties in RRC Districts 2, 3, and 4
Number of fields developed	6 fields
Development activity	2015–2039 (25 years)
Total development costs (2014$)	$5,677.8 million
Production activity	2019–2072 (54 years)
Oil production	420.58 million barrels
Value of production (2014$)	$45,291 million
Ad valorem taxes (2014$)	$4,740 million
Severance taxes (2014$)	$1,809 million
Private production royalties (2014$)	$7,548 million

Source: Denbury Onshore and Louis Berger analysis; *Based on average production curves.

Table 12 summarizes the economic benefits of the 20 Percent Scenario, including the benefits that would occur in each of the three RRC Districts.

Table 12. Economic Benefits of the 20 Percent Scenario

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
RRC Districts 2, 3, and 4				
Development Impacts, 2015–2039, Development Costs of $5.7 Billion				
Direct impacts	23,450 (938)	$1,953.0	$2,634.2	$4,542.2
Secondary impacts	19,708 (788)	$1,077.7	$1,877.7	$3,070.0
Total	43,158 (1,726)	$3,030.7	$4,511.9	$7,612.2
Production Impacts, 2019–2072, Net Production Revenues of $31.2 Billion				
Direct impacts	60,707 (1,124)	$7,495.9	$21,850.4	$31,193.4
Secondary impacts	72,265 (1,338)	$4,163.7	$7,144.4	$11,608.2
Total	132,972 (2,462)	$11,659.6	$28,994.8	$42,801.6

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

3.4 10 Percent Scenario

The "10 Percent Scenario" is defined as the estimated economic benefits if 10 percent of the total potential reserves were fully developed for fieldwide CO_2 EOR within 4 fields. Table 13 summarizes the development and production information for the 10 Percent Scenario for the fields in RRC Districts 2, 3, and 4. Note that this development scenario was not based on publicly announced or privately developed investment plans.

Table 13. Development and Production Assumptions for the 10 Percent Scenario

Project Component	Information
Counties with production	Sample counties in RRC Districts 2, 3 and 4
Number of fields developed	4 fields
Development activity	2015–2034 (20 years)
Total development costs (2014$)	$3,096 million
Production activity	2019–2069 (51 years)*
Oil production	229 million barrels
Value of production (2014$)	$24,633 million
Ad valorem taxes (2014$)	$2,624 million
Severance taxes (2014$)	$985 million
Private production royalties (2014$)	$4,106 million

Source: Denbury Onshore and Louis Berger analysis

*Based on average production curves.

Table 14 summarizes the estimated economic benefits of the 10 Percent Scenario, including the benefits that could occur in each of the three RRC Districts.

Table 14. Economic Benefits of the 10 Percent Scenario

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
RRC Districts 2, 3, and 4				
Development Impacts, 2015–2034, Development Costs of $3.1 Billion				
Direct impacts	12,404 (620)	$1,087.9	$1,456.9	$2,482.0
Secondary impacts	10,760 (538)	$601.1	$1,040.3	$1,700.3
Total	23,164 (1,158)	$1,689.0	$2,497.2	$4,182.3
Production Impacts, 2019–2069, Net Production Revenues of $17.9 Billion				
Direct impacts	32,794 (643)	$4,110.5	$11,867.5	$16,918.0
Secondary impacts	38,765 (760)	$2,305.9	$3,900.3	$6,322.5
Total	71,559 (1,403)	$6,416.4	$15,767.8	$23,240.5

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

4.0 Conclusions

The development and production activities associated with CO_2 EOR would provide considerable economic benefits to the Gulf Coast region. Even if only a small proportion of the potential EOR-recoverable reserves were developed, CO_2 EOR activities would bring significant jobs, income, and fiscal benefits to the Gulf Coast communities and the state. The economic and fiscal benefits are summarized in Table 15.

Table 15. Summary of Economic Benefits associated with the Development Scenarios (2014$)

Project Component	Full Build-out (Impacts to State)	30% Scenario (Impacts to RRC Districts)	20% Scenario (Impacts to RRC Districts)	10% Scenario (Impacts to RRC Districts)
Total development costs	$28.5 billion	$8.5 billion	$5.7 billion	$3.1 billion
Oil production	2,112.4 million barrels	629.51 million barrels	420.58 million barrels	229 million barrels
Ad valorem taxes	$22.8 billion	$7.1 billion	$4.7 billion	$2.6 billion
Severance taxes	$8.9 billion	$2.7 billion	$1.8 billion	$985 million
Private production royalties	$37.9 billion	$11.3 billion	$7.5 billion	$4.1 billion
Total sales supported by development	$46.9 billion	$11.3 billion	$7.6 billion	$4.2 billion
Total sales supported by production	$240.5 billion	$63.6 billion	$42.8 billion	$23.2 billion
Total annual average jobs supported by development	10,588 (25 years)	2,564 (25 years)	1,726 (25 years)	1,158 (20 years)
Total annual average jobs supported by production	14,758 (54 years)	3,660 (54 years)	2,462 (54 years)	1,403 (51 years)

Source: Denbury Onshore and Louis Berger analysis

5.0 References

Except where noted, all data and information was provided by Denbury Onshore.

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Appendix A

Table A-1. Fields Identified by BEG and DOE with High EOR Potential in RRC District 2

GULF COAST RESERVOIRS SCREENED ACCEPTABLE FOR CO2-EOR (U.S. DOE)			ATLAS OF TX MAJOR: OIL FIELDS-BUREAU OF ECONOMIC GEOLOGY (BEG)				POTENTIAL RECOVERABLE PRODUCTION
COUNTY	FIELD	FORMATION (DOE)	*FORMATION (BEG)	**YEAR UNITIZED	*ORIGINAL OIL IN PLACE (OOIP) MM (MILLION) BBLS	OOIP MM BBLS PER COUNTY TOTAL	RECOVERY FACTOR (RF) @ 0.17 MM (MILLION) BBLS
BEE	PETTUS PETTUS	PETTUS	PETTUS		46		7.82
					BEE CO	**46**	**7.82**
CALHOUN	HEYSER 5400	FRIO	5400		90		15.3
					CALHOUN CO	**90**	**15.3**
DE WITT	SLICK WILCOX	WILCOX	WILCOX		32		5.44
DE WITT	COTTONWOOD CR. SOUTH	WILCOX	NOT LISTED		22		3.74
					DE WITT CO	**54**	**9.18**
GOLIAD	BERCLAIR VICKSBURG	VICKSBURG	NOT LISTED		27		4.59
					GOLIAD CO	**27**	**4.59**
JACKSON	WEST RANCH GRETA	GRETA	GRETA		223		37.91
JACKSON	WEST RANCH 41-A	FRIO	41-A		203		34.51
JACKSON	WEST RANCH GLASSCOCK	FRIO	GLASSCOCK		127		21.59
JACKSON	WEST RANCH 98-A	FRIO	98-A		82		13.94
JACKSON	WEST RANCH WARD	FRIO	WARD		69		11.73
JACKSON	LA WARD NORTH	MARGINULINA	NOT LISTED		68		11.56
JACKSON	MAURBRO MARGINULINA	MARGINULINA	MARGINULINA	1971	51		8.67
JACKSON	GANADO WEST 4700	GRETA	4700		44		7.48
JACKSON	LOLITA MARGINULINA	MARGINULINA	MARGINULINA		32		5.44
JACKSON	LOLITA WARD ZONE	FRIO	WARD		29		4.93
JACKSON	FRANCITAS NORTH	FRIO	NOT LISTED		25		4.25
					JACKSON CO	**953**	**162.01**
KARNES	PERSON EDWARDS	EDWARDS	EDWARDS		56		9.52
KARNES	FALLS CITY LBAR., LPA.	LOWER WILCOX	LBAR, LPA		38		6.46
					KARNES CO	**94**	**15.98**
REFUGIO	TOM O'CONNOR 5900	FRIO	5900		549		93.33
REFUGIO	TOM O'CONNOR 5800	FRIO	5800	1976	422		71.74
REFUGIO	GRETA4400	FRIO	4400		313		53.21
REFUGIO	TOM O'CONNOR 5500	LOWER FRIO	5500		261		44.37
REFUGIO	LAKE PASTURE H-440 S	UPPER GRETA	H-440 S		132		22.44
REFUGIO	TOM O'CONNOR 4500 GR.	GRETA	4500 GRETA		59		10.03
REFUGIO	BONNIE VIEW	GRETA	NOT LISTED		50		8.5
REFUGIO	M. E. O'CONNOR FQ-40	FRIO	FQ-40		45		7.65
REFUGIO	TOM O'CONNOR 4400	FRIO	4400	1980	30		5.1
REFUGIO	LA ROSA5900	FRIO	5900		23		3.91
REFUGIO	LA ROSA 5400	FRIO	5400		20		3.4
					REFUGIO CO	**1904**	**323.68**
VICTORIA	PLACEDO 4700 SAND	GRETA	4700		77		13.09
VICTORIA	BLOOMINGTON 4600	GRETA	4600		69		11.73
VICTORIA	HELEN GOHLKE WILCOX	WILCOX	WILCOX		61		10.37
VICTORIA	MCFADDIN 4400	GRETA	4400		51		8.67
					VICTORIA CO	**258**	**43.86**
				TOTALS	**3,426**		**582.42**

*OOIP and Unit Date noted above are tied to the formation identified by the BEG. **Due to the voluntary unitization policy currently in place in Texas, the units noted above may include non-unitized gaps and holes within their unit boundary resulting in incomplete coverage of the entirety of the necessary formation. In the event that the units noted above contain gaps and holes resulting in a partially unitized field and incomplete coverage of the formation, then the existence of such gaps and holes in the unit will not allow for a complete coverage of such field and formation for the purposes of a potential CO_2 EOR project. Additionally, some of the units described may have since expired. Note that the status of some fields may have changed since this data was published in 1983 and 1996.

Table A-2. Fields Identified by BEG and DOE with High EOR Potential in RRC District 3

GULF COAST RESERVOIRS SCREENED ACCEPTABLE FOR CO2-EOR (U.S. DOE)			ATLAS OF TX MAJOR: OIL FIELDS-BUREAU OF ECONOMIC GEOLOGY (BEG)				POTENTIAL RECOVERABLE PRODUCTION
COUNTY	FIELD	FORMATION (DOE)	*FORMATION (BEG)	**YEAR UNITIZED	*ORIGINAL OIL IN PLACE (OOIP) MM (MILLION) BBLS	OOIP MM BBLS PER COUNTY TOTAL	RECOVERY FACTOR (RF) @ 0.17 MM (MILLION) BBLS
AUSTIN	RACCOON BEND COCKFIELD	COCKFIELD	COCKFIELD	1934	98		16.7
					AUSTIN CO	**98**	**16.7**
BRAZORIA	HASTINGS, W. FRIO	FRIO	FRIO		960		163.2
BRAZORIA	HASTINGS, E..U.FRIO	UPPER FRIO	UPPER FRIO		212		36.0
BRAZORIA	OLD OCEAN ARMSTRONG	FRIO	ARMSTRONG	1948	136		23.1
BRAZORIA	MANVEL F.B. II OLIG.	OLIGOCENE	OLIGOCENE	1934	67		11.4
BRAZORIA	MANVEL F.B. I OLIG.	OLIGOCENE	OLIGOCENE	1933	58		9.9
BRAZORIA	CHOCOLATE BAYOU, U.F.	UPPER FRIO	UPPER FRIO		33		5.6
BRAZORIA	OLD OCEAN CHENAULT	FRIO	CHENAULT		27		4.6
BRAZORIA	CHOCOLATE BAYOU, ALI.	AUBEL FRIO	AUBEL FRIO		15		2.6
					BRAZORIA CO	**1508**	**256.4**
BRAZOS	KURTEN WOODBINE	WOODBINE	WOODBINE		528		89.8
					BRAZOS CO	**528**	**89.8**
CHAMBERS	ANAHUAC MAIN FRIO	FRIO	MAIN FRIO		459		78.0
CHAMBERS	OYSTER BAYOU SEABREEZE	SEABREEZE	SEABREEZE		228		38.8
CHAMBERS	FIG RIDGE SEABREEZE	FRIO	SEABREEZE		94		16.0
CHAMBERS	TRINITY BAY FRIO 12	FRIO	FRIO 12	1950	52		8.8
CHAMBERS	CEDAR POINT FRIO 5900	FRIO	FRIO 5900		26		4.4
CHAMBERS	TURTLE BAY MIDDLETON	FRIO	MIDDLETON		18		3.1
					CHAMBERS CO	**877**	**149.1**
FORT BEND	THOMPSON FRIO	FRIO	FRIO		749		127.3
FORT BEND	SUGARLAND UPPER FRIO	UPPER FRIO	UPPER FRIO		148		25.2
FORT BEND	THOMPSON, S. 4400	MIOCENE	4400		70		11.9
FORT BEND	THOMPSON, N. U. VICKSBURG	UPPER VICKSBURG	VICKSBURG		52		8.8
FORT BEND	THOMPSON, S. 5400	MARGINULINA	5400		23		3.9
					FORT BEND CO	**1042**	**177.1**
GALVESTON	GILLOCK. S, BIG GAS	FRIO	BIG GAS	1966	78		13.3
GALVESTON	GILLOCK BIG GAS	FRIO	BIG GAS		48		8.2
GALVESTON	GILLOCK EAST SEGMENT	FRIO	EAST SEGMENT		44		7.5
					GALVESTON CO	**170**	**28.9**
HARDIN	SILSBEE FIRST YEGUA	YEGUA	FIRST YEGUA		41		7.0
HARDIN	BATSON CAPROCK	CAPROCK	CAPROCK		0		0.0
HARDIN	SOUR LAKE CAPROCK	CAPROCK	CAPROCK		0		0.0
					HARDIN CO	**41**	**7.0**
HARRIS	WEBSTER UPPER FRIO	UPPER FRIO	UPPER FRIO	1973	738		125.5
HARRIS	TOMBALL SCHULTZ SE	COCKFIELD	SCHULTZ SE		86		14.6
HARRIS	FAIRBANKS FAIRBANKS	YEGUA	FAIRBANKS		78		13.3
HARRIS	TOMBALL KOBS	COCKFIELD	KOBS		60		10.2
HARRIS	HOUSTON, S. FRIO	FRIO	FRIO		60		10.2
HARRIS	CLEAR LAKE FRIO	FRIO	FRIO		35		6.0
HARRIS	HOUSTON, S. MIOCENE	MIOCENE	MIOCENE		34		5.8
HARRIS	DURKEE FAIRBANKS	FAIRBANKS	FAIRBANKS		22		3.7
HARRIS	HUMBLE CAPROCK	CAPROCK	CAPROCK		0		0.0
					HARRIS CO	**1113**	**189.2**

*OOIP and Unit Date noted above are tied to the formation identified by the BEG. **Due to the voluntary unitization policy currently in place in Texas, the units noted above may include non-unitized gaps and holes within their unit boundary resulting in incomplete coverage of the entirety of the necessary formation. In the event that the units noted above contain gaps and holes resulting in a partially unitized field and incomplete coverage of the formation, then the existence of such gaps and holes in the unit will not allow for a complete coverage of such field and formation for the purposes of a potential CO_2 EOR project. Additionally, some of the units described may have since expired. Note that the status of some fields may have changed since this data was published in 1983 and 1996.

Table A-2 (Continued). Fields with High EOR Potential in RRC District 3

GULF COAST RESERVOIRS SCREENED ACCEPTABLE FOR CO2-EOR (U.S. DOE)			ATLAS OF TX MAJOR: OIL FIELDS-BUREAU OF ECONOMIC GEOLOGY (BEG)				POTENTIAL RECOVERABLE PRODUCTION
COUNTY	FIELD	FORMATION (DOE)	*FORMATION (BEG)	**YEAR UNITIZED	*ORIGINAL OIL IN PLACE (OOIP) MM (MILLION) BBLS	OOIP MM BBLS PER COUNTY TOTAL	RECOVERY FACTOR (RF) @ 0.17 MM (MILLION) BBLS
JEFFERSON	AMELIA FRIO 6	FRIO	FRIO 6		47		8.0
JEFFERSON	LOVELL'S LAKE FRIO 2	FRIO	FRIO 2	1965	42		7.1
JEFFERSON	LOVELL'S LAKE FRIO 1	FRIO	FRIO 1	1965	20		3.4
JEFFERSON	SPINDLETOP CAPROCK	CAPROCK	CAPROCK		0		0.0
					JEFFERSON CO	**109**	**18.5**
LEE	GIDDINGS AUSTIN CHALK	AUSTIN CHALK	AUSTIN CHALK		0		0.0
					LEE CO	**0**	**0.0**
LIBERTY	HARDIN FRAZIER	COCKFIELD	FRAZIER		43		7.3
LIBERTY	ESPERSON DOME S. CROCKETT	CROCKETT	CROCKETT		31		5.3
LIBERTY	MERCHANT EY-1B	YEGUA	1-B		23		3.9
					LIBERTY CO	**97**	**16.5**
MATAGORDA	MARKHAM N.-BCN CORNELIUS	FRIO	CORNELIUS	1952	36		6.1
MATAGORDA	SUGAR VALLEY N. LAURENCE	FRIO	LAURENCE		21		3.6
MATAGORDA	MARKHAM N.-BCN CARLSON	FRIO	CARLSON	1952	20		3.4
					MATAGORDA CO	**77**	**13.1**
MONTGOMERY	CONROE MAIN CONROE	COCKFIELD	MAIN CONROE	1978	1320		224.4
					MONTGOMERY CO	**1320**	**224.4**
POLK	LIVINGSTON YEGUA	YEGUA	YEGUA		56		9.5
POLK	SEGNO, DEEP WILCOX	UPPER WILCOX	DEEP WILCOX		42		7.1
POLK	LIVINGSTON WILCOX	WILCOX	WILCOX		42		7.1
POLK	SEGNO YEGUA	YEGUA	YEGUA		32		5.4
					POLK CO	**172**	**29.2**
SAN JACINTO	MERCY 8260 WILCOX	WILCOX	8260 WILCOX	1942	30		5.1
					SAN JACINTO CO	**30**	**5.1**
WALLER	KATY 1-B	YEGUA	1-B	1943	32		5.4
					WALLER CO	**32**	**5.4**
WHARTON	MAGNET-WITHERS	FRIO	NOT LISTED		163		27.7
WHARTON	WITHERS NORTH	MARGINULINA	NOT LISTED		100		17.0
WHARTON	PICKETT RIDGE	FRIO	NOT LISTED		27		4.6
					WHARTON CO	**290**	**49.3**
				TOTALS	**7,504**		**1,275.7**

*OOIP and Unit Date noted above are tied to the formation identified by the BEG. **Due to the voluntary unitization policy currently in place in Texas, the units noted above may include non-unitized gaps and holes within their unit boundary resulting in incomplete coverage of the entirety of the necessary formation. In the event that the units noted above contain gaps and holes resulting in a partially unitized field and incomplete coverage of the formation, then the existence of such gaps and holes in the unit will not allow for a complete coverage of such field and formation for the purposes of a potential CO_2 EOR project. Additionally, some of the units described may have since expired. Note that the status of some fields may have changed since this data was published in 1983 and 1996.

Table A-3. Fields with High EOR Potential in RRC District 4

GULF COAST RESERVOIRS SCREENED ACCEPTABLE FOR CO2-EOR (U.S. DOE)			ATLAS OF TX MAJOR: OIL FIELDS-BUREAU OF ECONOMIC GEOLOGY (BEG)				POTENTIAL RECOVERABLE PRODUCTION
COUNTY	FIELD	FORMATION (DOE)	*FORMATION (BEG)	**YEAR UNITIZED	*ORIGINAL OIL IN PLACE (OOIP) MM (MILLION) BBLS	OOIP MM BBLS PER COUNTY TOTAL	RECOVERY FACTOR (RF) @ 0.17 MM (MILLION) BBLS
ARANSAS	ARANSAS PASS	FRIO	NOT LISTED		44		7.48
					ARANSAS CO	**44**	**7.48**
DUVAL	LOMA NOVIA LOMA NOVIA	LOMA NOVIA	LOMA NOVIA		176		29.92
DUVAL	GOVT. WELLS, NORTH G.W.	GOVERNMENT	NORTH GW		150		25.5
DUVAL	SEVEN SISTERS G.W.	GOVERNMENT	GW		142		24.14
DUVAL	PIEDRE LUMBRE G.W.	GOVERNMENT	GW		95		16.15
DUVAL	CONOCO DRISCOLL U.1G.W.	GOVERNMENT	DRISCOLL U1G w	1937	69		11.73
DUVAL	HOFFMAN DOUGHERTY	JACKSON	DOUGHERTY		55		9.35
DUVAL	GOVT. WELLS, SOUTH G.W.	GOVERNMENT	SOUTH GW		40		6.8
					DUVAL CO	**727**	**123.59**
JIM HOGG	COLORADO COCKFIELD	COCKFIELD	COCKFIELD		52		8.84
JIM HOGG	PRADO MIDDLE LOMA NOVIA	LOMA NOVIA	LOMA NOVIA	1957	38		6.46
JIM HOGG	KELSEY M·2	CATAHOULA	M-2	1963	26		4.42
					JIM HOGG CO	**116**	**19.72**
JIM WELLS	SEELIGSON ZONE 19-C-4	FRIO	19 C-4		192		32.64
JIM WELLS	SEELIGSON ZONE 14-B	FRIO	ZONE 14-B		71		12.07
JIM WELLS	SEELIGSON ZONE 19-B	FRIO	19-B		45		7.65
JIM WELLS	WADE CITY BIERSTADT	FRIO	BIERSTADT		28		4.76
JIM WELLS	SEELIGSON ZONE 16	FRIO	ZONE 16		27		4.59
JIM WELLS	SEELIGSON ZONE 10	FRIO	ZONE 10		26		4.42
JIM WELLS	SEELIGSON ZONE 20-C	FRIO	20-C		23		3.91
					JIM WELLS CO	**412**	**70.04**
KLEBERG	T.C.B 21-B	FRIO	21-B		157		26.69
					KLEBERG CO	**157**	**26.69**
NUECES	STRATION BERTRAM WARDNER	FRIO	BERTRAM WARDNER		38		6.46
NUECES	FLOUR BLUFF PHILLIPS	FRIO	PHILLIPS		37		6.29
NUECES	LONDON GIN DOUGHTY	CATAHOULA	DOUGHTY		24		4.08
NUECES	ARNOLD DAVID CHAPMAN	FRIO	CHAPMAN		21		3.57
					NUECES CO	**120**	**20.4**
SAN PATRICIO	WHITE POINT E. BRIGHTON	FRIO	BRIGHTON		119		20.23
SAN PATRICIO	PLYMOUTH HEEP	FRIO	HEEP		113		19.21
SAN PATRICIO	PORTILLA 7400	FRIO	7400		75		12.75
SAN PATRICIO	MIDWAY MAIN MIDWAY	MIDWAY	MAIN MIDWAY		60		10.2
SAN PATRICIO	TAFT 4000	CATAHOULA	4000		45		7.65
SAN PATRICIO	PORTILLA 7300	FRIO	7300		25		4.25
					SAN PATRICIO CO	**437**	**74.29**
STARR	RINCON VICKSBURG SAND	VICKSBURG	VICKSBURG		35		5.95
STARR	GARCIA GARCIA MAIN	VICKSBURG	GARCIA MAIN		32		5.44
STARR	SUN FRIO D-1	FRIO	FRIO D-1		30		5.1
STARR	RINCON FRIO D-5	FRIO	FRIO D-5	1972	26		4.42
STARR	RINCON FRIO E1+E2	FRIO	FRIO E1+E2	1965	23		3.91
					STARR CO	**146**	**24.82**
WEBB	O'HERN PE1TUS	PE1TUS	PE1TUS	1957	83		14.11
WEBB	LOPEZ FIRST MIRANDO	MIRANDO	FIRST MIRANDO	1955	75		12.75
WEBB	MIRANDO CITY MIRANDO	MIRANDO	MIRANDO		46		7.82
WEBB	AVIATORS MIRANDO	MIRANDO	MIRANDO	1966	37		6.29
					WEBB CO	**241**	**40.97**
WILLACY	WILL.AMAR. W. W. WILLA.	WILLAMAR	WILLAMAR		161		27.37
WILLACY	WILL.AMAR WILL.AMAR	WILLAMAR	WILLAMAR		95		16.15
					WILLACY CO	**256**	**43.52**
ZAPATA	ESCOBAS MIRANDO	MIRANDO	MIRANDO		28		4.76
					ZAPATA CO	**28**	**4.76**
				TOTALS	**2684**		**456.28**

*OOIP and Unit Date noted above are tied to the formation identified by the BEG. **Due to the voluntary unitization policy currently in place in Texas, the units noted above may include non-unitized gaps and holes within their unit boundary resulting in incomplete coverage of the entirety of the necessary formation. In the event that the units noted above contain gaps and holes resulting in a partially unitized field and incomplete coverage of the formation, then the existence of such gaps and holes in the unit will not allow for a complete coverage of such field and formation for the purposes of a potential CO_2 EOR project. Additionally, some of the units described may have since expired. Note that the status of some fields may have changed since this data was published in 1983 and 1996.

Appendix B

Economic Benefits of Increased EOR along the Texas Gulf Coast

Louis Berger staff estimated the economic benefits of CO_2 EOR development for applicable fields on the Gulf Coast of Texas across RRC Districts 2, 3, and 4. According to BEG and DOE, there are 129 fields (excluding the Oyster Bayou and West Hastings Fields) in 36 counties in these three districts that have a high potential for CO_2 EOR development.

Because of the uncertainty associated with CO_2 EOR development, Louis Berger staff conducted the economic analysis for four development scenarios described as follows:

- "Full Build-out Scenario," which means the estimated economic benefits if 100 percent of the total number of fields identified by BEG and DOE in RRC Districts 2, 3, and 4 were fully developed for CO_2 EOR operations.
- "30 Percent Scenario," which means the estimated economic benefits if only 30 percent of the total potential reserves were fully developed for fieldwide CO_2 EOR within 16 fields.
- "20 Percent Scenario," which means the estimated economic benefits if 20 percent of the total potential reserves were fully developed for fieldwide CO_2 EOR within 6 fields.
- "10 Percent Scenario," which means the estimated economic benefits if 10 percent of the total potential reserves were fully developed for fieldwide CO_2 EOR within 4 fields.

The results of each scenario are discussed below.

B.1 Full Build-out Scenario RRC District 3

Louis Berger staff assumed that the Full Build-out Scenario in RRC District 3 would begin in 2015 and continue until 2029. Estimated capital costs to develop the fields in this district were $14.5 billion in 2014 dollars. Production was assumed to occur over 51 years, beginning in 2019 and ending in 2069. An estimated $35.1 billion in severance and ad valorem taxes and private production royalties were estimated to be paid to households and local and state governments. Table B-1 summarizes the development and production information associated with the Full Build-out Scenario of RRC District 3.

Table B-1. Development and Production Assumptions for Full Build-out Scenario RRC District 3

Project Component	Information
Counties with production	Austin, Brazoria, Brazos, Chambers, Fort Bend, Galveston, Hardin, Harris, Jefferson, Lee, Liberty, , Matagorda, Montgomery, Polk, San Jacinto, Waller, Wharton
Number of fields developed	55 fields
Development activity	2015–2029 (15 years)
Total development costs (2014$)	$14,495 million
Production activity	2019–2069 (51 years)*
Oil production	1,073 million barrels
Value of production (2014$)	$112,872 million
Ad valorem taxes (2014$)	$11,730 million
Severance taxes (2014$)	$4,563 million
Private production royalties (2014$)	$18,812 million

Source: Denbury Onshore and Louis Berger analysis

*Based on average production curves.

Capital investments of $14.5 billion over the 15-year construction and development period would support 7,247 average annual jobs. The capital investments would also bring $21 billion in sales and $13 billion in gross regional product to the Houston-Sugar Land-Baytown, Beaumont-Port Arthur, El Campo, and College Station-Bryan Metropolitan Statistical Areas and adjacent counties over the 15-year period (Table B-2).

In addition, production revenues would benefit the region and state, supporting jobs, income, and sales, as well as generating ad valorem and severance taxes and private production royalties. These revenues (less payments for taxes and royalties) would support 6,511 average annual jobs, $110 billion in sales, and $76 billion in gross regional product over the 51-year period (Table B-2).

Table B-2. Economic Benefits of Development and Production in RRC District 3

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Development Impacts, 2015–2029, Development Costs of $14.5 Billion				
Direct impacts	54,991 (3,666)	$5,372.3	$7,104.0	$11,781.4
Secondary impacts	53,717 (3,581)	$3,228.3	$5,450.5	$8,909.2
Total	108,708 (7,247)	$8,600.6	$12,554.5	$20,690.6
Production Impacts, 2019–2069, Net Production Revenues of $77.8 Billion				
Direct impacts	143,467 (2,813)	$21,356.9	$55,488.2	$77,767.8
Secondary impacts	188,585 (3,698)	$11,928.9	$20,022.7	$32,033.3
Total	332,052 (6,511)	$33,285.8	$75,510.9	$109,801.1

Notes: Values are in 2014 dollars

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

B.2 Full Build-out Scenario – RRC District 2

The Full Build-out Scenario for RRC District 2 was assumed to start in 2025 and continue until 2034. The capital costs to develop the fields in RRC District 2 were estimated to be $7.9 billion in 2014 dollars. Production from fields in the district was assumed to occur over 41 years, beginning in 2029 and ending in 2069. An estimated $16.8 billion in severance and ad valorem taxes and private production royalties were estimated to be paid to households and local and state governments. Table B-3 summarizes the development and production information associated with the full build-out of RRC District 2.

Table B-3. Development and Production Assumptions Full Build-out Scenario – RRC District 2

Project Component	Information
Counties with production	Bee, Calhoun, De Witt, Goliad, Jackson, Karnes, Refugio, and Victoria
Number of fields developed	33 fields
Development activity	2025–2034 (10 years)
Total development costs (2014$)	$7,862.7 million
Production activity	2029-2069 (41 years)*
Oil production	582.42 million barrels
Value of production (2014$)	$63,613 million
Ad valorem taxes (2014$)	$5,848 million
Severance taxes (2014$)	$2,413 million
Private production royalties (2014$)	$8,519 million

Source: Denbury Onshore and Louis Berger analysis

*Based on average production curves.

Capital investments of $7.9 billion over the 10-year construction and development phases would provide 5,423 average annual jobs in this district. The capital investments would bring $9 billion in sales and $5 billion in gross regional product to the Victoria metropolitan area and adjacent counties over this 10-year period (Table B-4).

In addition, production revenues would benefit the region and state, supporting jobs, income, and sales, as well as generating ad valorem and severance taxes and private production royalties. These revenues (less payments for taxes and royalties) would support 4,332 average annual jobs, $57 billion in sales, and $37 billion in gross regional product over the 41-year period (Table B-4).

Table B-4. Economic Benefits of Development and Production in RRC District 2

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Development Impacts, 2025–2034, Development Costs of $7.9 Billion				
Direct impacts	34,496 (3,450)	$2,239.0	$3,156.6	$6,040.1
Secondary impacts	19,732 (1,973)	$858.2	$1,635.5	$2,679.4
Total	54,228 (5,423)	$3,097.2	$4,792.1	$8,719.5
Production Impacts, 2029–2069, Net Production Revenues of $46.8 Billion				
Direct impacts	95,844 (2,338)	$7,876.6	$30,203.5	$44,732.0
Secondary impacts	81,738 (1,994)	$3,938.1	$7,108.0	$11,940.1
Total	177,582 (4,332)	$11,814.7	$37,311.5	$56,672.1

Note: Values are in 2014 dollars.

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

B.3 Full Build-out Scenario – RRC District 4

The Full Build-out Scenario for RRC District 4 was assumed to begin in 2030 and end by 2039. Capital costs to develop the fields in RRC District 4 were estimated to be $6.2 billion in 2014 dollars. Production was assumed to occur over 39 years, beginning in 2034 and ending in 2072. An estimated $15.6 billion in severance and ad valorem taxes and private production royalties was estimated to be paid to households and local and state governments. Table B-5 summarizes the development and production information associated with the full build-out of RRC District 4.

Table B-5. Development and Production Assumptions for Full Build-out Scenario in RRC District 4

Project Component	Information
Counties with production	Aransas, Duval, Jim Hogg, Jim Wells, Kleberg, Nueces, San Patricio, Starr, Webb, Willacy, and Zapata
Number of fields developed	41 fields
Development activity	2030–2039 (10 years)
Total development costs (2014$)	$6,159.8 million
Production activity	2034–2072 (39 years)*
Oil production	456.28 million barrels
Value of production (2014$)	$51,112 million
Ad valorem taxes (2014$)	$5,201 million
Severance taxes (2014$)	$1,877 million
Private production royalties (2014$)	$8,519 million

Source: Denbury Onshore and Louis Berger analysis

*Based on average production curves.

Capital investments of $6.2 billion over 10-years construction and development phases would support 4,921 average annual jobs. The capital investments would bring $7 billion in sales and $4 billion in gross regional product to the Brownsville, Corpus Christi, and Laredo metropolitan areas and adjacent counties over the 10-year period (Table B-6).

In addition, production revenues would benefit the region and state, supporting jobs, income, and sales, as well as generating ad valorem and severance taxes and private production royalties. These revenues (less payments for taxes and royalties) would support 3,930 average annual jobs, $46 billion in sales, and $30 billion in gross regional product over the 39-year period (Table B-6).

Table B-6. Economic Benefits of Development and Production in RRC District 4

Economic Impact Type	Jobs (Average Annual Jobs)*	Labor Income ($million)	Gross Regional Product ($million)	Sales ($million)
Development Impacts, 2030–2039, Development Costs of $6.2 Billion				
Direct impacts	28,377 (2,838)	$1,813.9	$2,566.5	$4,761.7
Secondary impacts	20,834 (2,083)	$845.0	$1,614.6	$2,686.3
Total	49,211 (4,921)	$2,658.9	$4,181.1	$7,448.0
Production Impacts, 2034–2072, Net Production Revenues of $35.5 billion				
Direct impacts	75,586 (1,938)	$6,072.5	$24,045.5	$35,514.8
Secondary impacts	77,678 (1,992)	$3,458.9	$6,391.2	$10,865.9
Total	153,264 (3,930)	$9,531.4	$30,436.7	$46,380.7

Note: Values are in 2014 dollars

*The first job number reports the total annual jobs supported over the life of the projects. The second number reports the average jobs supported on an annual basis.

Appendix C

Assumptions and Methodology

This appendix provides a discussion of the assumptions and methodology used to estimate the economic benefits of CO_2 EOR in the Gulf Coast of Texas region. This includes information regarding:

- IMPLAN model
- study areas
- phasing of development
- estimated capital costs
- production revenues
- fiscal receipts
- case studies

C.1 IMPLAN Model

This analysis used the IMpact on PLANning (IMPLAN) software and data system to estimate the economic impacts of oil and gas development and production. IMPLAN Professional customizes regional input-output (IO) models to provide estimates of economic output (sales), employment, income, and gross regional product effects in a specified location. IMPLAN is a widely-used government and industry-standard approach to estimate economic impacts for many types of issues. IO models systematically describe production and consumption sectors within a particular economy through a series of linkages among industries, households, and government. Changes to purchases of goods and services for final consumption (final demand change) drive IO models; in this case, the final demand changes are the oil and gas capital investments and production revenues. Each industry that produces goods and services generates demands for other goods and services. For example, when construction firms pay their workers (e.g., electricians and plumbers) and purchase supplies or services (e.g., lumber and concrete), economic activity is generated in the local or regional economy through jobs, income, and associated household spending. Multipliers are used to describe these iterations. Additionally, IMPLAN Version 3.0 has the capability to analyze 440 industry sectors, providing a detailed examination of the economic effects on specific industries.

C.2 Study Areas

Individual study areas were defined as an aggregation of counties that are linked economically for purposes of use within the IMPLAN model. Note that the study areas developed for this analysis include 44 counties—more than the 36 counties where the potential EOR fields are located. The additional counties were included because of the economic linkages that exist between those counties with and without potential development targets. The study areas were based on the following criteria:

- whether or not individual counties were identified as part of a Micropolitan or Metropolitan Statistical Area as defined by the U.S. Census Bureau
- proximity of a county to a Micropolitan or Metropolitan Statistical Area
- location of fields identified with high EOR potential and the availability of or proximity to sources of CO_2 within each county

Table C-1 lists the eight study areas and associated counties defined for the study.

Table C-1. Defined Study Areas

Study Area	County	RRC District
Beaumont-Port Arthur Metropolitan Statistical Area and additional counties	Hardin	3
	Jasper	
	Jefferson	
	Newton	
	Orange	
	Polk	
	Tyler	
Brownsville-Harlingen Metropolitan Statistical Area - McAllen-Edinburg-Mission Metropolitan Statistical Area - Rio Grande City - Roma Micropolitan Area - Raymondville Micropolitan Area and additional counties	Cameron	4
	Hidalgo	
	Starr	
	Willacy	
College Station-Bryan Metropolitan Statistical Area	Brazos	3
	Burleson	
	Robertson	
Corpus Christi Metropolitan Statistical Area - Kingsville Micropolitan Area - Alice Micropolitan Area - Beeville Micropolitan Area and additional counties	Aransas	4
	Jim Wells	
	Kennedy	
	Kleberg	
	Nueces	
	San Patricio	
El Campo Micropolitan Area - Bay City Micropolitan Area	Matagorda	3
	Wharton	
Houston - Sugar Land - Baytown Metropolitan Statistical Area	Austin	3
	Brazoria	
	Chambers	
	Fort Bend	
	Galveston	
	Harris	
	Liberty	
	Montgomery	
	San Jacinto	
	Waller	

Study Area	County	RRC District
Laredo Metropolitan Statistical Area and additional counties	Duval	4
	Jim Hogg	
	Webb	
	Zapata	
Victoria Metropolitan Statistical Area additional counties	Bee	2
	Refugio	
	Calhoun	
	De Witt	
	Goliad	
	Jackson	
	Karnes	
	Victoria	

C.3 Phasing of Development

Because there are a significant number of fields located in RRC Districts 2, 3, and 4 that have a high EOR potential, it is likely that development of these fields would take place over a period of time. To account for differences in timing, the project team staggered development over six phases under the full build-out scenario. These phases are defined as follows.

- Phase 1 is defined as fields located within RRC District 3 and within one of the counties that make up the Houston-Sugarland-Baytown Metropolitan Statistical Area in addition to Jefferson County, which is located in the Beaumont-Port Authur Metropolitan Statistical Area. Because EOR development is already occurring in this area and there are a number of large fields with high EOR potential concentrated in this area, it was logical of focus development in Phase 1 in this region. Full development of this phase would occur over 10 years given the number of fields and size of reserves.
- Phase 2 includes counties in RRC District 3 that are located outside the Houston-Sugarland-Baytown Metropolitan Statistical Area; including the Beaumont-Port Arthur Metropolitan Statistical Area, El Campo Metropolitan Statistical Area, and additional counties that are not included in a metropolitan or micropolitan statistical area. Development under Phase 2 is assumed to commence after the completion of Phase 1 and would take 5 years to complete with all fields starting production in year 5.
- Phase 3 includes those counties located predominantly along the east coast of RRC District 2. This includes counties in the Victoria Metropolitan Statistical Area and additional counties that are not included in a metropolitan or micropolitan statistical area. These counties contain a number of fields with high EOR potential or anthropocentric sources of CO_2. Development of Phase 3 and subsequent production is assumed to occur in tandem with the development of Phase 2.
- Phase 4 includes the remaining counties in RRC District 2 that are not included in Phase 3, including Bee County in the Beeville Metropolitan Statistical Area, and Dewitt, Goliad, and Karnes counties. Development of Phase 4 is assumed to take 5 years for full development with all fields starting production in year 5.
- Phase 5 includes a number of counties in RRC District 4, including the Corpus Christi Metropolitan Statistical Area, Kingsville Metropolitan Statistical Area, and Alice micropolitan

area. These counties contain a number of fields with high EOR potential or available sources of CO_2. Development of Phase 5 and subsequent production would occur in tandem with the development of Phase 4.

- Phase 6 includes the remaining counties in RRC District 4 that are not included in Phase 5, including Laredo Metropolitan Statistical Area, Rio Grande City-Roma micropolitan area, McAllen-Edinburg-Mission Metropolitan Statistical Area, Brownsville-Harlingen Metropolitan Statistical Area, and the Raymondville micropolitan area. Development of Phase 6 would take 5 years to complete with all fields starting production in year 5.

Production at each field was not assumed to occur until development has been completed. Full development was completed in each phase, with the exception of Phases 3 and 5, prior to the initiation of development in later phases. Production of 17 percent of the fields in Phase 1 started in 2019, while 17 percent of additional fields were brought online each year between 2020 and 2024, with 100 percent of all fields producing under a full development scenario by 2024. Phases 2 and 3 were assumed to occur at the same time because the areas addressed by these phases are geographically close to the areas covered in the prior phase and development in each phase would likely occur concurrently without priority for one phase over the other. Phases 4 and 5 were assumed to occur at the same time for the same reasons outlined in Phases 2 and 3. See Table C-2 below for start dates and total development times for each phase

Table C-2. Timing of Development Phases

Phase	Estimated Start Date for Development	Total Development Time (years)
Phase 1	2015	10
Phase 2	2025	5
Phase 3	2025	5
Phase 4	2030	5
Phase 5	2030	5
Phase 6	2035	5

C.4 Development and Operation Costs

Total lease operating and capital costs utilized in this report were based on Oyster Bayou Field Unit estimates provided by Denbury Onshore of $44/barrel. Louis Berger staff determined that approximately one-third of the capital costs were attributed to field labor, one-third were attributed to materials, and one-third were attributed to development of a recycling facility.

Allocation of cost among IMPLAN sectors for the recycling facility was determined based on actual facility costs for seven fields (some outside of Texas) already developed by Denbury Onshore. The average spending profile for each of the sub-categories for the recycling facility and the relevant IMPLAN sector to which the cost sub-category was applied are shown in Table A-3.

In addition, electric power generation (transmission and distribution) was added as 3.5 percent of the total cost of development of the recycling facility as a result of additional data obtained from Oyster Bayou's capital costs. Field development (not including the recycling facility development), including labor and materials was weighted as two-thirds of the total development costs in the IMPLAN profile. These field development costs were applied to construction (IMPLAN sector 36), oil and gas well drilling (IMPLAN sector 28), and support activities for oil and gas (IMPLAN sector 29).

Table C-3. Recycling Facility Costs

Major Category	Sub-Category	Percent of Total	IMPLAN Sector
Equipment	ATM tanks	2.6%	189
	Heat exchangers	5.2%	188
	In-line instrumentation	3.4%	251
	Packaged equipment	11.0%	319
	Pipe and fittings	14.0%	170
	Pressure vessels	4.4%	189
Instrumentation & Electrical Power	Control systems	1.9%	251
	Electrical equipment R&M	0.1%	244
	Electrical parts	0.1%	251
	Electrical powerline	0.1%	See below
	High voltage power equipment	1.8%	269
	Instrumentation and electrical power construction	3.0%	See below
	Motor controls and building	0.9%	269
Internal labor and overhead	Internal labor and overhead	3.3%	20
Other	Miscellaneous	7.6%	See below
Project management and engineering	Consulting services	5.2%	369
	Inspection services	0.7%	375
	Regulatory fees	0.1%	432
Site construction	Mechanical construction	31.1%	See below
Total		96.5%	-

Because much of the construction profile for the recycling facility was specified by Denbury Onshore, Louis Berger staff needed to customize the IMPLAN approach for the general non-residential construction expenditures. For these construction expenditures, Louis Berger staff used a modified construction industry spending profile and labor income change in IMPLAN. Industries that already existed in the recycling facility costs were removed from the industry spending profile so as to not double count the spending on these sectors. The allocation of the construction costs between industry spending and labor was used from IMPLAN for the construction sector in each study area. Table C-4 summarizes the IMPLAN capital cost spending profile.

Table C-4. IMPLAN Profile for Capital Costs

Sector	Description	Allocation
36	Construction of other new nonresidential structures	22.2%
170	Iron and steel mills and ferroalloy manufacturing	4.7%
188	Power boiler and heat exchanger manufacturing	1.7%
189	Metal tank (heavy gauge) manufacturing	2.4%
244	Electronic capacitor, resistor, coil, transformer, and other inductor manufacturing	0.0%
251	Industrial process variable instruments manufacturing	1.8%
269	Relay and industrial control manufacturing	0.9%
319	Wholesale trade	3.7%
20	Oil and gas extraction	1.1%
432	Other state and local government enterprises	0.0%
375	Environmental and other technical consulting services	0.2%
28	Drilling oil and gas wells	22.2%
369	Architectural, engineering, and related services	1.8%
29	Support activities for oil and gas operations	22.2%
31	Electric power generation, transmission, and distribution	1.2%
-	Construction industry spending and labor income	13.9%
Total		100.0%

The construction industry spending profile for Sector 36 was modified to remove the sectors in Table C-5, because they were already included in the recycling facility capital cost profile.

Table C-5. Sectors Removed from Industry Spending Profile

IMPLAN Sector ID	Sector Name
3031	Electricity, and distribution services
3170	Iron and steel and ferroalloy products
3188	Power boilers and heat exchangers
3189	Metal tanks (heavy gauge)
3319	Wholesale trade distribution services
3369	Architectural, engineering, and related services
3374	Management, scientific, and technical consulting services
3375	Environmental and other technical consulting services

Louis Berger staff ran the IMPLAN model with the manufacturing and wholesale sectors margined (Sectors 170 and 319). For all of the micropolitan and metropolitan study areas, the local capture rate (i.e., the local purchase percentage) was used from the Social Accounting Matrix in IMPLAN to describe the potential non-local support of the development. However, the following IMPLAN sectors were identified as 100 percent local:

- Support Activities for Oil and Gas (29)
- Non-Residential Construction (36)

For the state IMPLAN model, the local purchase percentage for Other State and Local Government Enterprises and the Oil and Gas Extraction sectors were also analyzed at 100 percent. All costs and revenues for the analysis were reported in 2014 dollars. Development costs were escalated at the rate of inflation. EOR field development was assumed to occur over 4 years at a constant annual cost.

C.5 Production Revenues

Based on Denbury Onshore's experience with CO_2 in Texas and elsewhere, the tertiary production from each field was estimated to be 17 percent of the original oil in place. The production at each field was assumed to follow the production curve described in Table C-6.

Table C-6. Field Type and Production Periods

Field Type	Incline Time (years)	Plateau Time (years)	Decline Time (years)
Large	6	6.5	30
Average	4.5	5.5	25
Small	4	5	20

For the fields evaluated in the Gulf Coast region, the average recoverable reserves per field were estimated to be 17 million barrels. For this analysis, large fields were defined as those having 34 million barrels or more of potential recoverable reserves and small fields were defined as having 5 million barrels or less of potential recoverable reserves.

Production revenues were estimated using a long-term base case nominal price per barrel estimated by the DOE, Energy Information Agency (U.S. EIA, 2014). A 3 percent discount rate was used to calculate the 2014 dollar value of production revenues to estimate economic impacts. Prior to analyzing production revenues in IMPLAN, the estimated severance, ad valorem, and private production royalties were removed from the production revenues. All production revenues were analyzed with IMPLAN Sector 20: Extraction of Oil and Natural Gas, at 100 percent local capture rate (i.e., local purchase percentage).

C.6 Fiscal Receipts

Louis Berger staff consulted with and followed the guidance of several experts at the Texas Comptroller's Office to develop the methodology for estimating oil and gas severance and ad valorem taxes in Texas. For severance taxes, production revenue is taxed at 2.3 percent of the total market value of oil recovered for the first 10 years of production and then is taxed at 4.6 percent of the total market value of oil recovered beginning in year 11 until the life of the well is complete. These taxes are paid to the state of Texas and, unlike in other states, are not shared with local government entities (Bowlin, 2014).

County ad valorem taxes were estimated by combining the average mill levy for school districts in each county with the county mill levy. This combined average mill levy was then applied to the value of remaining reserves less lifting costs ($25/barrel [Texas Comptroller's Office]) in any given year (discounted back to the present year) to determine the taxable value of production (Texas Comptroller Office, 2014a). The lifting cost was escalated at the same rate as the price of oil over the production period. The total value of all oil reserves was discounted annually using a discount rate of 14.57 percent, which was provided by the Texas Comptroller's office (Property Tax Division) and is based on the 2013 Property Value Study Base Discount Rate (Texas Comptroller Office, 2014b).

No taxes were estimated for equipment and infrastructure associated with the well fields because the infrastructure would have a relatively small tax revenue impact on state and local taxes compared to the value of recovered oil (severance taxes) and recoverable oil remaining in place (ad valorem).

C.7 Case Studies (Hastings and Oyster Bayou Fields)

The following section summarizes the assumptions and approach used to estimate the economic benefits of the Hasting and Oyster Bayou field developments.

Capital Costs

Denbury Onshore provided the capital costs for Oyster Bayou. Denbury Onshore also provided the recycling facility itemized costs that were used to specify the IMPLAN categories for equipment, materials, architectural and engineering, environmental planning services, state payments, power, and other construction expenses for the recycling facility. Approximately 33 percent of the recycling facility expenditures were identified as mechanical construction. For the mechanical construction category, because equipment, materials, and specific services were already provided in the recycling facility capital expenses profile, the project team customized the construction sector (IMPLAN 36) industry spending profile and construction labor income so as not to double count the sectors already included in the profile. The labor income percentage (of mechanical construction) was assumed to be consistent with that of the construction sector, which was 50 percent for the Houston-Sugar Land-Baytown metropolitan statistical area.

The remaining capital cost items included well work, field infrastructure, and land. Expenditures for well work and field infrastructure were assumed to be undertaken evenly by three sectors: oil well drilling; support sectors for oil and gas development; and non-residential construction. Land expenditures were assumed to be on-the-ground labor to acquire lease agreements and access from surface owners.

For the capital expenditures spending profile, the local capture rates for the Houston-Sugar Land-Baytown IMPLAN model were used for all sectors except the oil and gas support, non-residential construction, and electric power sectors, which were all set to 100 percent local. In the state IMPLAN model, the state and local government and oil and gas extraction sectors were also set to 100 percent local. Materials and equipment purchases were margined to reflect the allocation of expenses among retail, manufacturing, and transportation sectors, if the margins were available from IMPLAN. Costs were assumed to be in 2012 dollars.

A similar approach was used to estimate capital cost direct effects in IMPLAN for the Hasting Field. Total capital costs for the Hasting Field were obtained from Denbury Onshore and estimated to be $300 million. Actual recycling facility itemized costs were also obtained from Denbury Onshore and used to specify the IMPLAN categories for the recycling facility. Total recycling facility costs were $203.9 million. The remaining current capital costs, $96 million, were allocated among power, well work, field infrastructure, and land expenses. The approach for these sectors in IMPLAN was the same as described above for the Oyster Bayou costs. All approaches for the local capture rates and margins were the same as described for Oyster Bayou. These costs were assumed to be in 2012 dollars.

Production Revenues

Louis Berger staff estimated production revenues attributable to the Hastings and Oyster Bayou fields using information provided by Denbury Onshore and reported by the DOE. Denbury Onshore provided the 2013 Oyster Bayou production. Monthly production was summed across all wells for 2013, resulting in total 2013 production of approximately 1.2 million barrels. The average price of oil for 2013 ($108/barrel) was obtained from the Energy Information Administration and applied to annual production for each field to estimate the value of this production. Denbury Onshore paid $3.0 million of production taxes for Oyster Bayou; royalties were estimated to be 16.7 percent of the value of production. Taxes and royalties were removed from the value of production and run in IMPLAN through the oil and gas extraction sector (in 2012 dollars) because they were not spent to support the oil operations.

Louis Berger staff used a similar approach for the production revenues from the Hastings Field. Denbury Onshore provided the oil production information for 2012 for the Hastings Field of 5,573 barrels per day. The daily production was multiplied by 365 to estimate annual production of 2.0 million barrels. The price of oil was obtained from the Energy Information Administration for 2012 ($112) and used to estimate the value of oil production. Denbury Onshore paid production taxes of $7.4 million and royalties were estimated to be 16.7 percent of the value of production. These taxes and royalties were removed from the value of production and run through the oil and gas extraction sector in IMPLAN.

Disclaimer: All results are based upon the assumptions in this memorandum. Neither Denbury Onshore or Louis Berger warrants nor guarantees that the cost, expenses or resultant production or revenue realized in the two examples upon which this memorandum is based will result in the same fiscal receipts from the remaining 129 fields referenced in this report.