The Financial Prospects for a Coal-Based IGCC Plant with Carbon Capture Serving California

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ABSTRACT

This paper describes the economic and financial viability of a coal-based power plant concept that employs carbon dioxide (CO_2) capture and is located either in California or close enough to California to sell its electricity to that market. The captured CO_2 is sold to oil well owners for injection into the wells to enhance oil recovery. This effectively sequesters most of the CO_2, eliminating it as a greenhouse gas. The plant gasifies coal and uses the synthesis gas produced in an integrated gasification combined cycle. When CO_2 collection and sequestration is also practiced, we dub such plants "IGCC+S." Other equipment is added to the IGCC+S concept plant to make the plant especially environmentally friendly: it is fitted with enhanced sulfur and NOx emission control equipment needed to meet the strict environmental requirements for electric generators set by the California Air Resources Board.

The analysis was performed for two possible regulatory approaches for electric generation: avoided cost, or cost-of-service pricing, and estimated market, or deregulated, pricing. Two locations for the IGCC+S concept plant were investigated: the San Joaquin Valley in California and the Four Corners location in New Mexico, with the electricity exported to serve the California market. This IGCC+S type plant would compete for electric sales in the California market beginning around year 2010. Estimates were made for how future fuel price changes and potential future generating fleet configurations might affect electric prices in the California region. The current fleet of 1400 generating units in California was analyzed to anticipate how it may evolve to meet increased demand over the next few years, mostly from the addition of new natural-gas fueled units. The fuel consumption and economics of each unit in this expanded fleet were characterized in hour-by-hour dispatch. This allowed the development of a stacking order for the units on the basis of their present operating costs. Altered threshold bid prices for the fleet under several fuel price scenarios allowed the re-stacking of this threshold bid price order. California's expected future electric price structure was analyzed, and a projection of the potential return to investors from electric sales was developed for the study time frame 2010-2025. From this, the nature of the competitive market that IGCC+S plants would enter was inferred. This allowed assessment of the level of capacity factor the IGCC+S plants were likely to exhibit based on their production costs and dispatch potential against that of the competing fleet, and an assessment of the revenue stream such a plant was likely to earn through competitive electric sales. The study shows that capacity factor for IGCC+S units is limited by their availability, which was assumed to be 85%.

When fitted for carbon dioxide capture, IGCC plants located in California or the Four Corners region of New Mexico could supply electricity to California and sell the captured CO_2 for enhanced oil recovery (EOR) either in California or the Permian Basin (in West Texas and New Mexico). Internal rates of return for several configurations of such IGCC+S plants are computed and fall in the range 16 – 31%. The analysis shows that total financial return from baseload electric sales in the state and from the sale of CO_2 makes such a project profitable without subsidy or need of carbon tax.

INTRODUCTION

California is in need of new baseload generation, so consideration of new approaches to providing it is timely. The coal-based IGCC technology considered in this paper would need to be equipped with extensive environmental control equipment to provide exceptionally low environmental emissions. In addition, supplying the unit with carbon dioxide removal equipment to capture the CO_2 would allow the unit to reduce significantly the amount of greenhouse gas that is released. Compared to state-of-art natural gas combined cycle, IGCC+S plants would emit about 1/4 the carbon dioxide per net kWh. Captured CO_2 has economic value in the regions chosen, since it can be sold to oil well owners for practice of EOR. The San Joaquin Valley and Four Corners locations are both convenient sites for generating electricity for use in California and for generating CO_2 for EOR in California or the Permian Basin.

Consideration of use of IGCC+S in California is supported by the following:

- There is a critical need for additional diversity in California's baseload generating capacity, reducing dependence on natural gas,
- Electric prices there are among the highest in the U.S., and
- There is an unserved market in California for CO_2 for practice of EOR.

Locating a coal-fueled power plant in California would be a daunting licensing problem, as the State of California has some of the most stringent air quality standards in the world. However, if the plant were clean enough, such as the one investigated here, it should be possible to obtain siting permits. In this evaluation, each coal-fired unit was supplied with supplementary environmental control equipment for SO_2 and NOx that added cost, but gives these units environmental emission levels equivalent to those of a natural-gas-fueled combined cycle.

Notwithstanding that the IGCC+S plants described in this study would meet environmental requirements for electric generators set by the California Air Resources Board, it was prudent also to evaluate a more licensing-friendly location that could serve the California electric market. One such location is the Four Corners region of New Mexico. A plant located there would export electricity to California, and send its CO_2 through existing CO_2 pipelines to oil fields in the Permian Basin.

This evaluation looks at the economic prospects of employing IGCC+S for electric sales within or supplied to California, for plants located in one of the following locations:

- Within California, in the San Joaquin Valley, with the CO_2 used for EOR in California oil fields;
- In the Four Corners region of New Mexico, with the electric load serving California, and the CO_2 sent by existing pipeline for practice of EOR in Permian Basin oil fields.

APPROACH

Several cases were selected to demonstrate the financial robustness of IGCC+S technology in these regions. For most of the cases developed, it was assumed both electricity and CO_2 would be sold. However, some cases were also developed in which only electricity or only CO_2 was sold. There is also a consideration of the method used for establishing the selling price of electricity. Two methods were developed to estimate electric sales from the units. One, with lower projected revenue, makes its price estimates using an avoided cost of a combined cycle generating unit fueled by natural gas, and the other, a more sophisticated methodology, estimates the electric price using presumptions about prices that might be expected in a competitive market. For those cases, it was decided to evaluate the IGCC+S plants at the two sites under the competitive market price developed from NETL's GEMSET program system[1,2].

Overall, a total of seven cases were structured as summarized below:

- Case A – IGCC+S in the San Joaquin area with CO_2 sequestration using avoided cost pricing;
- Case B – IGCC in the San Joaquin area without CO_2 sequestration using avoided cost pricing;
- Case C – IGCC+S in the San Joaquin area with CO_2 sequestration using estimated market pricing;
- Case D – IGCC+S in the Four Corners area with CO_2 sequestration in the Permian Basin using avoided cost pricing;
- Case E – IGCC in the Four Corners area without CO_2 sequestration using avoided cost pricing;
- Case F – IGCC+S in the Four Corners area with CO_2 sequestration in the Permian Basin using estimated market pricing; and
- Case G – A stand alone case of just the CO_2 sequestration using revenues from the sale of the CO_2.

The major financial assumptions utilized in this analysis are briefly summarized here:

- Revenues from the sale of electricity are based on two methodologies: (1) an avoided cost associated with the installation of a combined cycle generating unit fueled by natural gas; and (2) an estimate of market prices in California assuming a similar market structure as is currently used in a power marketing system used in the eastern U.S., PJM. The total avoided cost pricing consists of the fuel component, O&M, and fixed capital plus administration. For the Cases in which the plant is located in the Four Corners area, the electric pricing is adjusted for transmission costs to deliver into California.
- Fuel prices were based on the estimates from the 2002 GEMSET Fuels Price Characterization Database through 2024.
- All costs and revenues are in current dollars.
- It was assumed that the project would be based on a private supplier being the owner, and a capitalization structure of 30% equity and 70% debt.
- Interest rates were assumed to be 8% with a 0.25% commitment fee.
- Interest during construction would be capitalized.
- Revenue from the sale of CO_2 would be computed by a methodology using a factor based on the world price of oil. Transportation costs were based on a current tariff from a major pipeline company specializing in movements of CO_2.
- The construction period begins in the third quarter of 2006, and the plant is assumed to become operational in the first quarter of 2010. The operational period of the analysis goes through 2024, which is when the 15-year bond financing is completed.

All of the seven cases were evaluated using a financial model developed for independent power producers (IPP) for financing demonstrations. This model has been utilized in numerous projects throughout the U.S. and in other countries. For each case, the following was prepared:

- A Capitalization Schedule which indicates the capital funding each year of construction and the utilization of the proceeds from the financing;
- A Debt Service Schedule which shows the annual interest and principal repayments;
- A Statement of Income that indicates the expected revenues from the sale of electricity and CO_2, and the expenses associated with the production cost of the unit. It also shows the depreciation calculated for the project, the interest expenses, and the estimated taxes on the project. It also shows the retained earnings of the project, which are then used for payments to equity participants, and working capital.
- An Analysis of Cash and Cash Balances associated with the project on an annual basis;
- A Balance Sheet, and finally
- A calculation of the project's return on Equity.

Detailed financial results for all Cases is given in the project report.[2]

RESULTS AND DISCUSSION

California Regional Data

Load Forecast. In 2000, the California Energy Commission published its latest demand and energy forecast for the State of California. In addition to the Commission forecast, the Energy Information Agency (EIA) publishes a long-term forecast for each state, currently extending to the year 2020. The present study used a combination of these load growth forecasts, as well as historical data, to synthesize hour-by-hour demand profiles throughout the study's time horizon. The expectation is that peak demand is increasing at a greater rate than the minimum demands. That information and the relationship between the annual peak hour and every other hour in the year allowed for the creation of the load duration curves utilized in the study to price electricity, and which are shown in Figure 1.

Fleet Makeup. California has a unique mix of generation resources, unlike every other region in the U.S. With less than 1% coal-fired generating units, California relies heavily on natural gas and hydro units for the bulk of its power. It also has significant percentages of renewable resources such as wind, solar, geothermal, and significant cogeneration resources. By 2010, there will be a need to add over 33,000 MW to the existing fleet to enable California to meet its capacity obligations. Approximately 12,200 MW of existing generation was assumed retired during the time frame between 2002 and 2010, consisting primarily of old natural gas (9,241 MW) and cogeneration (2,495 MW) units. The net increase in the fleet was comprised of 1,000 MW of wind generation and the balance (33,000 MW) as natural gas combined cycle and peaking units. This resulted in the fleet makeup as shown in Figure 2. All other categories were held basically constant with only the wind and natural gas generation increasing.

By 2010, it is estimated that California will have more than 70% of its generation in natural gas, and total installed firm capacity (adjusted) of approximately 70,000 MW. This compares to the situation in 2002, when total nameplate capacity was slightly more than 57,000 MW of which 45% used natural gas. Year 2020 was estimated in a similar fashion to 2010. The fleet expected then is estimated to provide approximately 89,000 MW of capability. By the end of this time frame, unless California embraces a return of nuclear energy, the State would be relying on almost 80% of its generation from natural gas. This could expose the State to price spikes as have been experienced in the recent past.

Figure 1. GEMSET Estimated Load Duration Curves for California

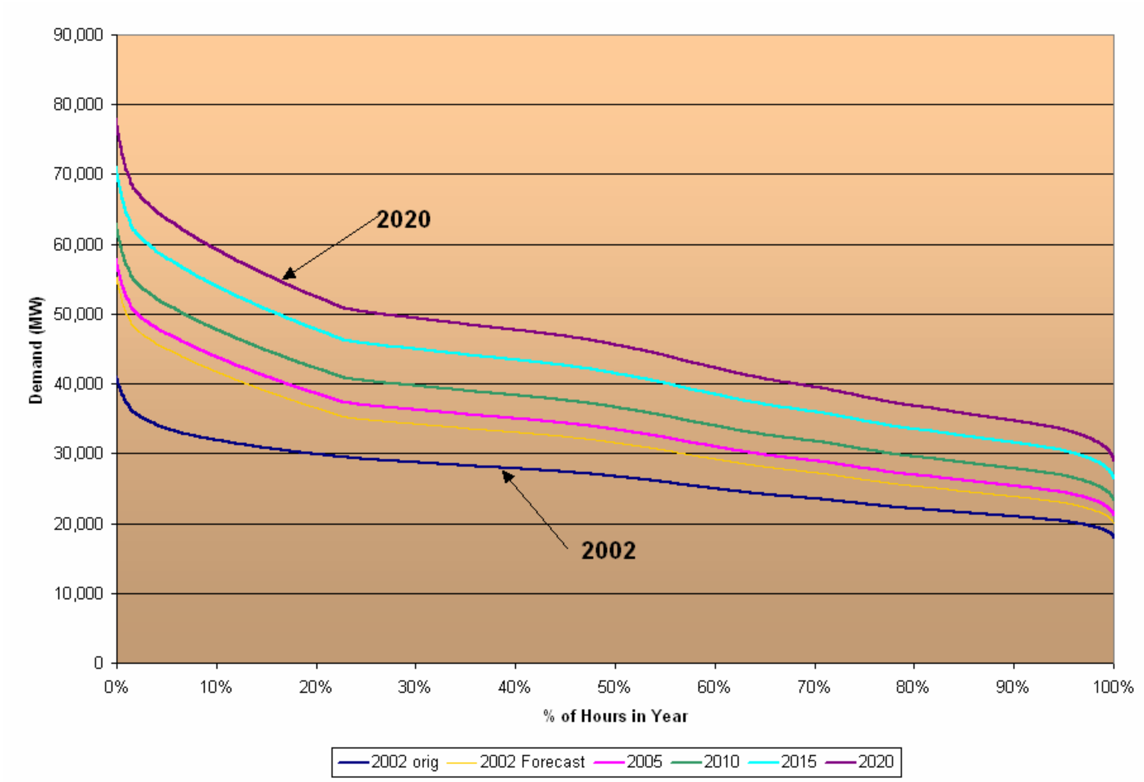
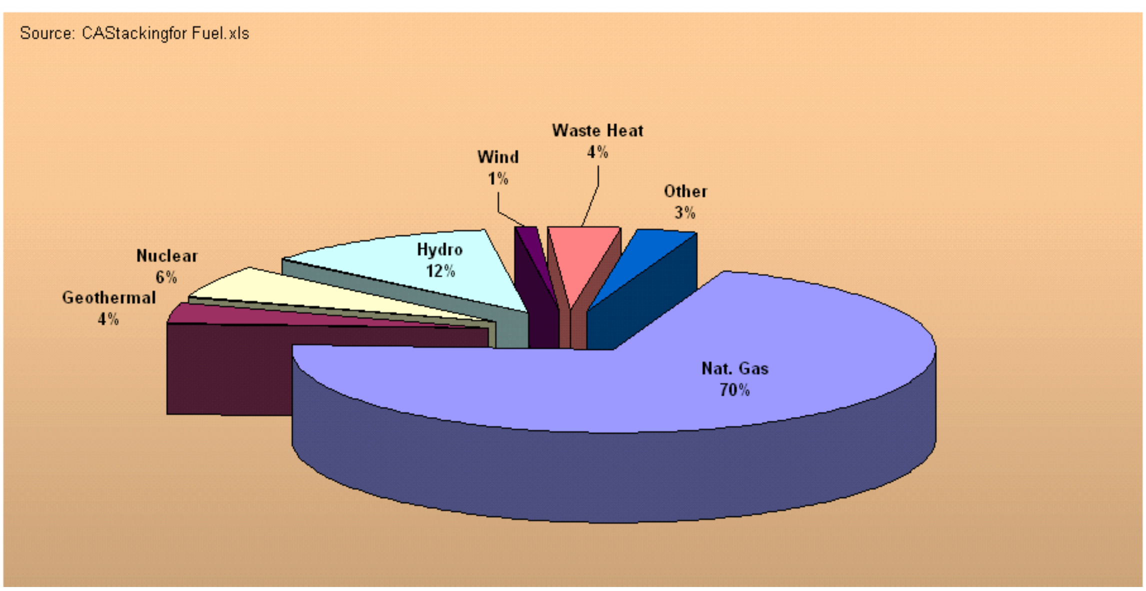
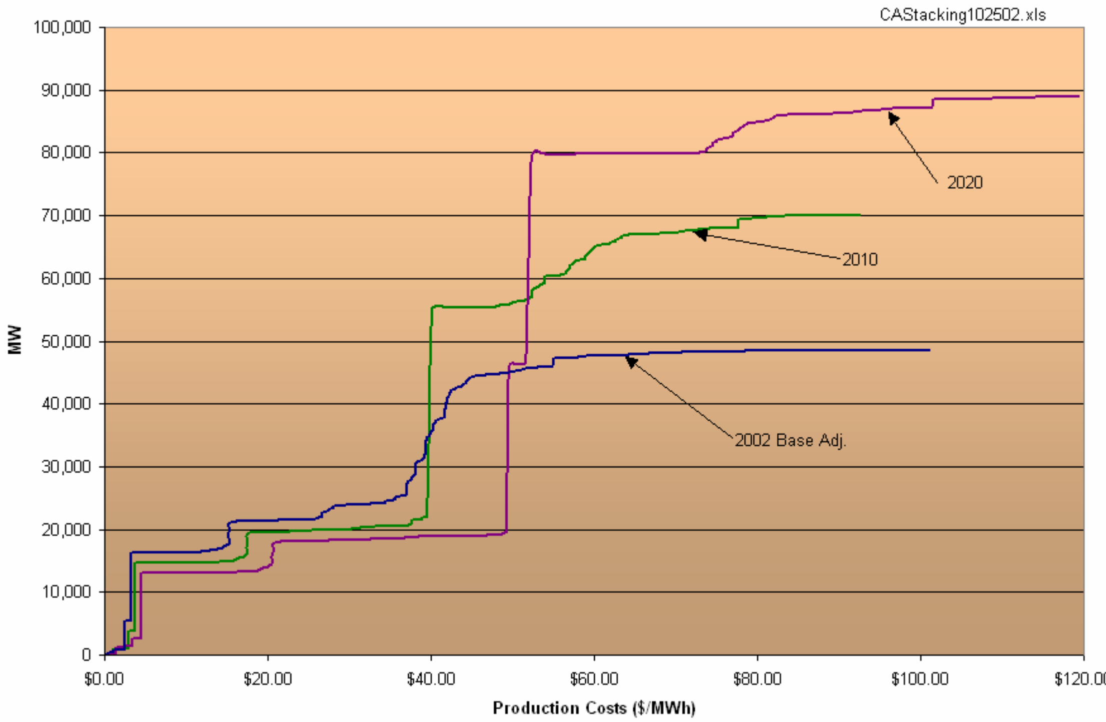


Figure 2. Projected California Generating Fleet (2010-Adj); Year 2020 Increases Natural Gas-Fueled Generation to 79% of the Total



Three distinct estimates of generating capacity in California in years 2002, 2010, and 2020 are stacked according to their production costs from low to high. This represents the estimated stacking order for dispatch purposes in the analysis. This indicates where an IGCC+S plant would be in the production order stack and how many hours it could reasonably be expected to run in the California market. In Figure 3, the production costs of the three fleet stackings are shown for the three years highlighted.

Figure 3. GEMSET Estimates of Production Costs Versus Demand

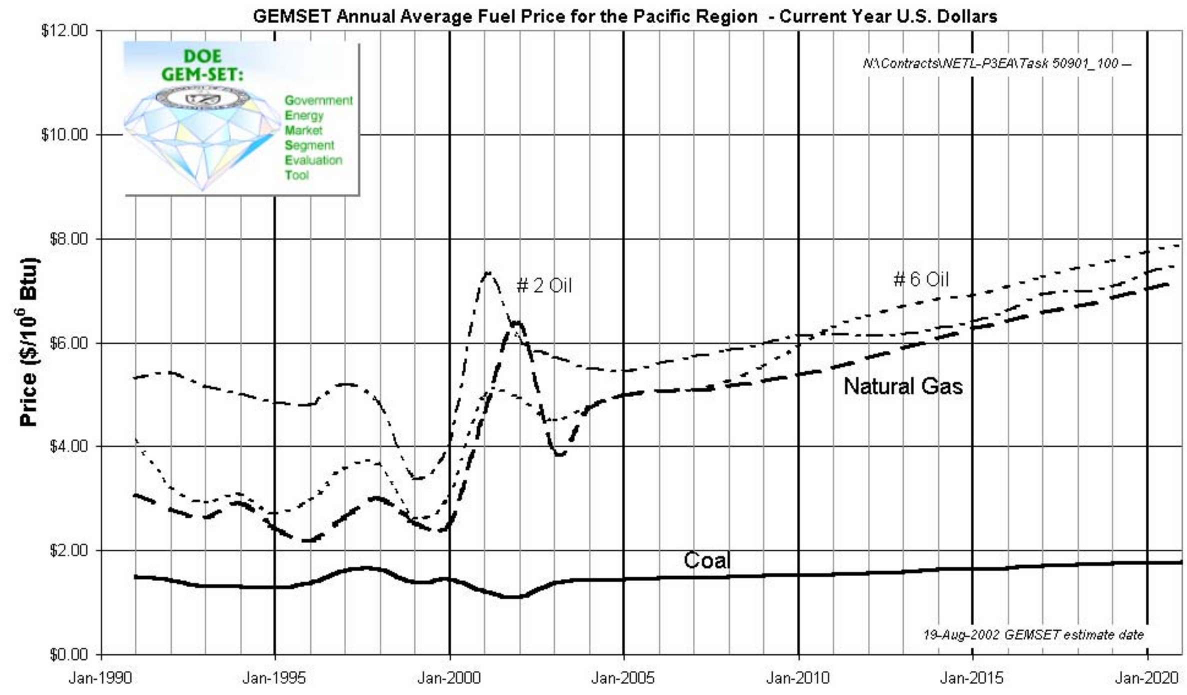


FINANCIAL CONSIDERATIONS

Major Fuels. Delivered fuel price projections from the GEMSET 2002 Fuel Price Characterization[1] were used to evaluate the fuel costs during the years of operation of power generating plants in this study. The fuel price projections for FERC Region 9, Pacific Region, were used for plants in California. The fuel price projections for FERC Region 8, Mountain Region, were used for the IGCC plant located in the Four Corners region of New Mexico. Baseline annual average historical and projected delivered natural gas, No. 2 and No. 6 oils, and coal fuel prices for the Pacific Region, in current-year dollars, are shown in Figure 4 as computed by the GEMSET model[1]. These GEMSET fuel price forecasts combine historical delivered fuel price data from FERC, spot market closing prices, NYMEX fuel futures prices, and EIA long-term forecasts of fuel price escalation. These prices are higher than those projected from the National Energy Modeling System (NEMS). A similar projection was made for the Mountain Region, for the Four Corners analysis.

Other Fuels. There are other units in the California service area that use a range of different fuels. These fuels contribute only a very small fraction of generation, so their depiction is not as detailed in the GEMSET assessments[2]. All fuel prices are adjusted to a current-year dollars basis using the GEMSET projected Implicit Price Deflator (IPD)[1].

Figure 4. Natural Gas, No. 2 and No. 6 Oils, and Coal Annual Average Fuel Prices - Pacific Region



Fuel and Production Cost Calculations. For many generating units, the fuel cost associated with that unit is the largest single cost component of the cost of electricity (COE). The total cost of fuel is a function of the fuel price, discussed above, and the heat rate associated with that unit.

For this analysis, a database of every unit on the California system has been identified and the heat rate of that unit obtained from a variety of sources. To obtain the fuel cost of a unit, the capacity factor of the unit is also required. Capacity factor is defined as:

$$Cf = \frac{kWh}{nameplate\ rating \bullet period\ hours}$$

Thus capacity factor is a function of the load and hours the unit actually operated over a period of time.

In this analysis, estimates are made of the capacity factors of a unit, and then the heat rate is applied to obtain the total fuel cost when the nameplate rating of the unit is utilized.

Operating and Maintenance Costs. Another cost component that must be identified for this analysis is the variable cost of operating and maintaining the unit so that it functions when actually dispatched by the Independent System Operator (ISO). Since each unit has its own particular set of operating costs, it was decided to utilize reasonable industry averages for the differing types of units. In the GEMSET database for stacking units according to their production costs, an element of operating and maintenance costs are utilized for each type of unit on the system. This cost is in addition to the cost of fuel.

Method 1 – Projecting Electric Price based on "Avoided Costs"

Method 1 is based on the premise that the State of California is arguing before the FERC for its current contracts. In that complaint before FERC, California is stating that a reasonable profit for any supplier should be based on the “avoided cost” of building and operating a combined cycle natural gas fired generating unit.

In this type of analysis, one employs the capital cost of such a unit and a rate of return on that capital of about 18% (fixed charge rate), plus the fuel and operating costs associated with that type of unit. Since fuel cost is the major component of operating costs for natural gas units, an assumed price of natural gas is utilized to determine that portion of the operating costs. At the current time, they are assuming a price for natural gas of about \$3.50/Mcf (about \$3.50/10^6 Btu). After adding a small component for fixed and other variable O&M, today’s fair price for electricity is estimated to be around \$45.00/MWh.

Figure 5. Electric Price Based on Avoided Cost for NGCC

Year	Pacific Natural Gas Cost Current \$	Fuel Cost \$/kWh	Fixed (Capital) (\$/kWh)	Variable O&M (\$/kWh)	Administrative (\$/kWh)	Avoided Cost Pricing COE (\$/kWh)
2010	\$5.517	\$0.038	\$0.013	\$0.005	\$0.005	\$0.061
2011	\$5.697	\$0.039	\$0.013	\$0.005	\$0.005	\$0.062
2012	\$5.890	\$0.041	\$0.013	\$0.005	\$0.005	\$0.064
2013	\$6.087	\$0.042	\$0.013	\$0.005	\$0.005	\$0.065
2014	\$6.262	\$0.043	\$0.013	\$0.005	\$0.006	\$0.067
2015	\$6.418	\$0.044	\$0.013	\$0.005	\$0.006	\$0.068
2016	\$6.567	\$0.045	\$0.013	\$0.005	\$0.006	\$0.069
2017	\$6.703	\$0.046	\$0.013	\$0.005	\$0.006	\$0.070
2018	\$6.862	\$0.047	\$0.013	\$0.005	\$0.006	\$0.072
2019	\$7.029	\$0.048	\$0.013	\$0.005	\$0.006	\$0.073
2020	\$7.214	\$0.050	\$0.013	\$0.006	\$0.006	\$0.074
2021	\$7.345	\$0.051	\$0.013	\$0.006	\$0.006	\$0.076
2022	\$7.479	\$0.052	\$0.013	\$0.006	\$0.006	\$0.077
2023	\$7.615	\$0.053	\$0.014	\$0.006	\$0.007	\$0.079
2024	\$7.753	\$0.053	\$0.014	\$0.006	\$0.007	\$0.080

For the projections in this analysis, the price of natural gas used in the GEMSET projections was used to determine fuel costs, while capital and the other O&M costs are increased by the Implicit Price Deflator to adjust for inflation. In Figure 5 the total avoided cost price of electricity is presented as utilized in the analysis as the price available to IGCC+S plants in California.

Method 2 – Projecting Electric Price and Revenue Based on a Competitive Market

In the second method for estimating price, detailed descriptions of the generating system were developed for three years, 2002, 2010, and 2020. Unit by unit estimates of operating costs were used to prepare figures of production cost stacking versus demand. A statistical technique was employed to use data from an independent system operator in a stably functioning competitive market, PJM, to estimate price vs. demand functions that could be expected in California. Histograms of expected "energy-only" electric price vs. percentage of the year at or below that price were computed. From the projections developed it is possible to estimate unit revenue. The analysis showed that dispatch of IGCC+S plants would be excellent, with dispatch limited by availability, not economics of operation. For this study it was assumed the IGCC+S plants would operate at 85% capacity factor. Details are shown in the project report.[2] A comparison of the revenue expected of CAISO (California Independent System Operator) units in the fleet that would dispatch at 85% capacity factor and for IGCC+S plants in San Joaquin and Four Corners locations is given in Figure 6.

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Figure 6. IGCC+S Compared to Fleet Unit with Operating Costs to Dispatch at 85% Capacity Factor

Year	Forecast CASIO Demand		Production Cost	Capacity Factor	Annual Operating Hours	Expected Energy-Only Return		Cost of Production	Available for Profit, and to Service Fixed O&M + Debt
2002	24,625 MW	**CASIO fleet**	$ 34.99/MWh	85.00%	7,446	$ 86.21/MWh	$ 641,904/MW per year	$ 260,554/MW per year	$ 381,350/MW per year
		IGCC+S San Joaquin	$ 18.28/MWh			$ 86.21/MWh	$ 641,904/MW per year	$ 136,113/MW per year	$ 505,791/MW per year
		IGCC+S Four Corners	$ 15.12/MWh			$ 80.21/MWh	$ 597,228/MW per year	$ 112,584/MW per year	$ 484,644/MW per year
2010	28,704 MW	**CASIO fleet**	$ 39.58/MWh	85.00%	7,446	$ 81.55/MWh	$ 607,230/MW per year	$ 294,726/MW per year	$ 312,504/MW per year
		IGCC+S San Joaquin	$ 20.59/MWh			$ 81.55/MWh	$ 607,230/MW per year	$ 153,313/MW per year	$ 453,917/MW per year
		IGCC+S Four Corners	$ 16.60/MWh			$ 75.88/MWh	$ 564,968/MW per year	$ 123,604/MW per year	$ 441,364/MW per year
2020	35,749 MW	**CASIO fleet**	$ 49.23/MWh	85.00%	7,446	$ 103.34/MWh	$ 769,484/MW per year	$ 366,582/MW per year	$ 402,902/MW per year
		IGCC+S San Joaquin	$ 23.91/MWh			$ 103.34/MWh	$ 769,484/MW per year	$ 178,034/MW per year	$ 591,450/MW per year
		IGCC+S Four Corners	$ 16.52/MWh			$ 96.15/MWh	$ 715,929/MW per year	$ 123,008/MW per year	$ 592,921/MW per year

Line delivery charges require that energy-only price at Four Corners be lower to result in equivalent delivered price

	2002	**2010**	**2020**
Line Delivery Price in Four Corners	$ 80.21/MWh		
Year 2002 wheeling charge from Four Corners to California Delivery	$ 6.00/MWh		
Delivery Price to California Grid	$ 86.21/MWh		
[Four Corners Energy-Only Price] / [California Delivered Energy-Only Price] = constant	93.04%	93.04%	93.04%
	Basis		

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CO_2 MARKET DATA AND ASSUMPTIONS

California Market for Oil Well CO_2

During the year 2000, approximately 307.4 million barrels of oil were produced in California oilfields from 46,999 wells.[3] California ranked fourth among the oil-producing states, behind Louisiana, Texas, and Alaska, respectively. Approximately 82% of the oil produced in California, or 253.2 million barrels, was produced from onshore fields. Of that, about 86%, or 217.3 million barrels, came from oil fields in the eight counties comprising the San Joaquin Valley, which included the five largest oil fields in the state. Most of the oil produced in the San Joaquin Valley is heavy oil (20° API gravity and below). As a result, thermal enhanced oil recovery (steam flooding EOR) is common, with about 130 million barrels of incremental oil production from thermal EOR in the two districts (Districts 4 and 5) in which the San Joaquin Valley is located.

Enhanced oil recovery via CO_2 flooding is most efficient at conditions for miscible CO_2 displacement (generally for reservoirs deeper than 1,200 meters with oil lighter than 22° API gravity), where the injected CO_2 mixes thoroughly with the oil in the reservoir such that the interfacial tension between the two substances effectively disappears.[4] However, with heavier oils or more shallow reservoirs, immiscible CO_2 displacement, where the injected CO_2 remains physically distinct from the oil within the reservoir, although less efficient, may still improve oil recovery by causing the oil to swell, reducing the oil density and improving mobility.

The U.S. Department of Energy, National Energy Technology Laboratory, National Petroleum Technology Office (NPTO) recently used their Total Oil Recovery Information System (TORIS) reservoirs database to perform a preliminary screening of oil reservoirs in California for applicability to enhanced oil recovery via CO_2 flooding. The results of the reservoir screening for all of California as provided by the NPTO, shown in Figure 7, indicate that 52 oil fields pass the screening; that is, these fields satisfy the physical characteristic screening criteria for EOR via CO_2 flooding. Of these, twenty-two are in the San Joaquin Valley (shown in Figure 8). These fields were then evaluated based on two criteria: 1) does the field become available for CO_2 flooding within a 25-year period beginning in 2000; that is, secondary flooding (water flooding) which is typically performed before CO_2 flooding is no longer economical within the 25-year period; and 2) is the ratio of the present value of the net income (NPV) from EOR via CO_2 flooding over the life of the EOR project to the investment greater than one, based on a West Texas Intermediate (WTI) oil price of \$25/bbl and CO_2 price of \$1/Mcf. The investment cost estimated by the TORIS is based on the capital costs associated with converting the oil reservoirs from secondary oil recovery (water flooding) to CO_2 flood EOR (tertiary recovery). CO_2 is treated in the TORIS analysis as a consumable purchased based on a price of \$1/Mcf delivered to the reservoir.

Ten of the 52 fields in California (noted by EOR values greater than zero in Figure 7) satisfied the evaluation criteria, three of which are located in the San Joaquin Valley. The amount of CO_2 produced from a 388 MWe IGCC+S plant located in the San Joaquin Valley is estimated to be about 43.2 billion scf annually at a plant capacity factor of 85%. Therefore, about 36 years of CO_2 production from this size plant could be sequestered in these two San Joaquin Valley oil fields, or, assuming a plant life of 10 years, three such size plants could be supported.

Figure 7. Results of Preliminary Screening TORIS Database for California Reservoirs Meeting Physical Criteria

CO2 Results for WTI oil price = $25/bbl

This is a TORIS Run assuming a constant price.

OOIP - Original Oil in Place
EOR - Oil Recoverable Due to CO2 Flooding
CO2-P - Purchased CO2 (Net CO2)
GR CO2 - Total CO2 Injected (Gross CO2)
RATIO - CO2 Purchased per Barrel of Oil Produced
ROR - Rate of Return assuming no inflation

STATE	FIELD NAME	RESERVOIR NAME	OOIP (MMBBLS)	EOR (MMBBLS)	CO2-P (BCF)	GR CO2 (BCF)	RATIO (MCF/STB)	ROR
CA	EDISON	VEDDER F	226	0	2	3	41.99	0
CA	CYMRIC	OCEANIC(	103	0	1	1	74.99	0
CA	VENTURA	C BLOCK	1600	150	1693	2409	11.31	1
CA	SANTA FE SPRIN	G MAIN ARE	2609	0	13	13	76.25	0
CA	DOS CUADRAS	FEDERAL	750	0	7	7	79.75	0
CA	RAISIN CITY FI	E ZILCH SA	115	0	0	0	0	0
CA	ASPHALTO	STEVENS	64	0	2	2	90.41	0
CA	RINCON	MILEY-MA	280	0	0	0	0	0
CA	SATICOY	PICO	68	0	0	0	0	0
CA	SAN MIGUELITO	FIRST GR	127	14	145	198	10.12	8
CA	SAN MIGUELITO	SECOND G	79	11	128	164	11.28	1
CA	RINCON	OAK GROV	51	0	5	5	36.55	0
CA	BUENA VISTA	27-B	203	0	1	1	78.73	0
CA	BUENA VISTA	ANTELOPE	222	0	0	0	0	0
CA	COALINGA	NOSE ARE	937	108	1047	1390	9.69	5
CA	ELK HILLS	STEVENS	2365	0	22	22	96.19	0
CA	GREELEY	VEDDER	178	0	4	4	47.35	0
CA	KETTLEMAN HILL	S VAQUEROS	105	0	0	0	0	0
CA	EN SECTION	MAIN ARE	240	0	3	3	85.52	0
CA	SUMMERLAND OFF	S VAQUEROS	65	0	3	3	93.53	0
CA	COYOTE WEST	EMERY E	63	6	70	102	11.97	4
CA	LOS ANGLES DOW	N MIOCENE	58	0	2	2	22.36	0
CA	GUIJARRAL HILL	S MAIN ARE	82	11	82	101	7.6	9
CA	OXNARD	MCINNES	125	0	2	2	89.23	0
CA	NEWHALL-POTERO	5TH ZONE	60	0	2	2	49.34	0
CA	COLES LEVEE NO	R RICHFIEL	350	48	513	680	10.79	2
CA	COLES LEVEE SO	U STEVENS	200	0	4	4	77.24	0
CA	CUYAMA SOUTH	HOMAN	830	0	10	12	41.11	0
CA	VENTURA FIELD	B SANDS	102	9	101	140	10.69	18
CA	SANTA SUSANA	SECOND A	50	0	3	4	48.67	0
CA	VENTURA	D-7,8	625	0	12	12	32.43	0
CA	SOUTH MOUNTAIN	BRIDGE-P	90	0	4	4	77.94	0
CA	PALOMA	PALOMA S	208	0	6	6	53.59	0
CA	KETTLEMAN DOME	TEMBLOR	1299	0	12	12	73.05	0
CA	BELRIDGE NORTH	BELRIDGE	195	0	2	2	38.3	0
CA	VENTURA	D 3,4,5,	1100	123	1246	1611	10.1	5
CA	BEVERLY HILLS	EAST ARE	42	0	1	1	57.93	0
CA	COYOTE WEST	EMERY WE	49	0	1	1	93.7	0
CA	GREELY	STEVENS	31	0	0	1	42.87	0
CA	HONOR RANCHO	WAYSIDE	22	0	1	1	88.19	0
CA	INGLEWOOD	SENTOUS	30	0	1	1	55.79	0
CA	KETTLEMAN HILL	S UPPER MC	48	0	0	0	0	0
CA	MONTALVO WEST	MCGRATH	21	0	1	1	72.55	0
CA	NEWHALL - POTR	E 3RD ZONE	46	0	1	1	65.79	0
CA	NEWHALL - POTR	E 6TH ZONE	24	0	1	1	52.3	0
CA	RAILROAD GAP	ANTELOPE	18	0	0	0	44.23	0
CA	SAN MIGUELITO	THIRD GR	22	0	0	0	51.46	0
CA	SATICOY	SANTA BA	14	1	13	16	10.05	11
CA	SHIELLS CANYON	EOCENE	38	0	1	1	30.48	0
CA	TEJON GR - TEJ	O CENTRAL	48	0	1	1	56.2	0
CA	TEN SECTION	441	13	0	1	1	82.25	0
CA	VENTURA AVENUE	GRUBB D-	19	0	1	1	35.34	0
TOTALS			16309	481	5171	6949		

Both the Coalinga and Coles Levee North oil fields in the San Joaquin Valley are reported by the NPTO to have an original oil in place (OOIP) greater than 100 million barrels. Additionally, based on the capital and O&M costs for an IGCC+S plant relative to an IGCC plant without CO_2 removal in the San Joaquin Valley, the cost of removing CO_2 and compressing it to pressures required for entry into a pipeline would be about \$0.67/Mcf of CO_2 (2002 dollars), assuming a capitalization charge rate of 15%. Based on an estimated CO_2 transportation cost of \$0.35/Mcf[8], the cost to collect and transport the CO_2 to the oil fields would meet the \$1/Mcf target. Use of the Massachusetts Institute of Technology (MIT) Pipeline Transport Model to estimate the cost of installing and operating a pipeline transporting CO_2 locally within the San Joaquin Valley (assuming a distance of 50 miles) results in an estimated CO_2 transportation cost of less than \$0.10/Mcf.

Figure 8. Results of Preliminary Evaluation of Reservoirs in San Joaquin Valley

CO2 Results for WTI oil price = $25/bbl

This is a TORIS Run assuming a constant price.

OOIP - Original Oil in Place
EOR - Oil Recoverable Due to CO2 Flooding
CO2-P - Purchased CO2 (Net CO2)
GR CO2 - Total CO2 Injected (Gross CO2)
RATIO - CO2 Purchased per Barrel of Oil Produced
ROR - Rate of Return assuming no inflation

STATE	FIELD NAME	COUNTY CODE	COUNTY	RESERVOIR NAME	OOIP (MMBBLS)	EOR (MMBBLS)	CO2-P (BCF)	GR CO2 (BCF)	RATIO (MCF/STB)	ROR
CA	COALINGA	19	Fresno	NOSE ARE	937	108	1047	1390	9.69	5
CA	COLES LEVEE NO	29	Kern	R RICHFIEL	350	48	513	680	10.79	2
CA	GUIJARRAL HILL	19	Fresno	S MAIN ARE	82	11	82	101	7.6	9
CA	ELK HILLS	29	Kern	STEVENS	2365	0	22	22	96.19	0
CA	KETTLEMAN DOME	19	Fresno	TEMBLOR	1299	0	12	12	73.05	0
CA	PALOMA	29	Kern	PALOMA S	208	0	6	6	53.59	0
CA	GREELEY	29	Kern	VEDDER	178	0	4	4	47.35	0
CA	COLES LEVEE SO	29	Kern	U STEVENS	200	0	4	4	77.24	0
CA	EN SECTION	29	Kern	MAIN ARE	240	0	3	3	85.52	0
CA	EDISON	29	Kern	VEDDER F	226	0	2	3	41.99	0
CA	ASPHALTO	29	Kern	STEVENS	64	0	2	2	90.41	0
CA	BELRIDGE NORTH	29	Kern	BELRIDGE	195	0	2	2	38.3	0
CA	CYMRIC	29	Kern	OCEANIC(	103	0	1	1	74.99	0
CA	BUENA VISTA	29	Kern	27-B	203	0	1	1	78.73	0
CA	TEJON GR - TEJ	29	Kern	O CENTRAL	48	0	1	1	56.2	0
CA	TEN SECTION	29	Kern	441	13	0	1	1	82.25	0
CA	RAISIN CITY FI	19	Fresno	E ZILCH SA	115	0	0	0	0	0
CA	BUENA VISTA	29	Kern	ANTELOPE	222	0	0	0	0	0
CA	KETTLEMAN HILL	31	Kings	S VAQUEROS	105	0	0	0	0	0
CA	GREELY	29	Kern	STEVENS	31	0	0	1	42.87	0
CA	KETTLEMAN HILL	31	Kings	S UPPER MC	48	0	0	0	0	0
CA	RAILROAD GAP	29	Kern	ANTELOPE	18	0	0	0	44.23	0
TOTALS					7250	167	1703	2234		

Based on this preliminary assessment, there appears to be a market for the CO_2 produced from an IGCC+S plant located in the San Joaquin Valley. A more detailed assessment of the oil reservoirs in the state, particularly in the San Joaquin Valley, should be performed with criteria more specific to the IGCC+S operating assumptions of this study. The preliminary assessment looked at reservoirs that would be available for CO_2 flooding over a 25-year period beginning in 2000. An assessment should be made for the 2010 to 2020 period for which the economic feasibility of IGCC+S is being evaluated in this study. The WTI oil price was held constant at \$25/bbl for the preliminary assessment.

New Mexico and West Texas Market for Oil Well CO_2

There are oil fields in the Four Corners region and existing CO_2 pipelines from that region to Texas. Thus, for an IGCC+S unit located at Four Corners, the CO_2 market would be for both regions.

About 379 million barrels of crude oil was produced in Texas in 2001 from 159,357 wells.[5] A review of the Texas Railroad Commission Texas Oil Industry Statistics[6] indicates that almost half of the crude oil, about 178 million barrels, was produced from fields in the Permian Basin in West Texas from about 52,175 wells. New Mexico produced about 68.4 million barrels of crude oil in 2000, with the majority (about 60 million barrels) being produced in the Permian Basin in southeast New Mexico.[7] About 1.5 million barrels was produced from oil fields in northwest New Mexico. The Permian Basin of west Texas and New Mexico accounts for nearly all current U.S. CO_2 floods, and demand is fairly constant at about 438 billion cubic feet of CO_2 per year because CO_2 floods are long-lived projects that are difficult to stop and restart.[8]

The NPTO recently performed a preliminary screening of the TORIS reservoir database for this study to identify reservoirs and oil fields in Texas and New Mexico that meet the physical criteria assumed for the study for CO_2 flooding. The fields were then evaluated based on the same evaluation criteria described for the California oil reservoir evaluation. As a result of the screening and evaluation, one hundred twenty-five (125) oil fields in Texas and 20 oil fields in New Mexico were identified as passing the screening criteria and having a rate of return on investment required to implement CO_2 flooding of greater than 10%. The amount of oil that could potentially be recovered from these fields via CO_2 flooding was estimated to be about 3.94 billion barrels in Texas and 190 million barrels in New Mexico, or about 10% of the OOIP, as shown in Figure 9. The purchase CO_2 requirement for flooding these fields is estimated to total about 40,400 billion cubic feet at an average of 10.5 Mcf/bbl. Of the 125 oil fields identified in Texas, at least 43 of those are located in the Permian Basin in west Texas, as shown in Figure 10.

Based on the preliminary screening and evaluations, the EOR potential of these fields in combination with the New Mexico fields, shown in Figure 11, is estimated to be about 1.4 billion barrels of oil, requiring the purchase of about 14,000 billion cubic feet of CO_2. This would be equivalent to the CO_2 removed from IGCC+S plants producing over 12,600 MWe over a 10-year period, or 4,200 MWe over a 30 year period.

Based on the positive results of this preliminary assessment of the market for CO_2 produced from IGCC+S plants located in New Mexico to service the California electric market, a more detailed assessment considering the conditions discussed for the California CO_2 market should be performed.

Figures 10 and 11 show the TORIS results for West Texas (via the existing pipeline), and New Mexico, with a short local pipeline.

Figure 9. Results of Preliminary Screening and Evaluation of TORIS Reservoir Database for Texas and New Mexico Oil Reservoirs

CO2 Results for WTI oil price = $25/bbl, Reservoirs with greater than 10% ROR

This is a TORIS Run assuming a constant price.

OOIP - Original Oil in Place
EOR - Oil Recoverable Due to CO2 Flooding
CO2-P - Purchased CO2 (Net CO2)
GR CO2 - Total CO2 Injected (Gross CO2)
RATIO - CO2 Purchased per Barrel of Oil Produced
ROR - Rate of Return assuming no inflation

STATE	OOIP (MMBBLS)	EOR (MMBBLS)	CO2-P (BCF)	GR CO2 (BCF)	AVG. RATIO (MCF/STB)	AVG. ROR
Texas	37715	3937	38153	52043	10.4	25.1
New Mexico	1884	190	2145	2868	10.6	36.1

Figure 10. Results of Preliminary Evaluation of Oil Fields Located in Permian Basin in West Texas

CO2 Results for WTI oil price = $25/bbl, with greater than 10% ROR

This is a TORIS Run assuming a constant price.

OOIP - Original Oil in Place
EOR - Oil Recoverable Due to CO2 Flooding
CO2-P - Purchased CO2 (Net CO2)
GR CO2 - Total CO2 Injected (Gross CO2)
RATIO - CO2 Purchased per Barrel of Oil Produced
ROR - Rate of Return assuming no inflation

STATE	FIELD NAME	RESERVOIR NAME	OOIP (MMBBLS)	EOR (MMBBLS)	CO2-P (BCF)	GR CO2 (BCF)	RATIO (MCF/STB)	ROR
TX	ADAIR	WOLFCAMP	110	9	109	129	12.1	17.0
TX	ADAIR	SAN ANDR	168	14	185	260	13.2	23.0
TX	ANDREWS WOLFCA	M WOLFCAMP	109	12	102	139	8.5	23.0
TX	BEDFORD	DEVONIAN	42	5	45	60	9.0	18.0
TX	BENEDUM	SPRABERR	292	27	330	420	12.2	29.0
TX	COWDEN NORTH	DEEP	176	25	147	192	5.9	19.0
TX	COWDEN SOUTH	CANYON	258	31	257	359	8.3	36.0
TX	CRAWAR	DEVONIAN	23	3	26	32	8.7	11.0
TX	CROSSETT	DEVONIAN	53	6	106	146	17.7	23.0
TX	CROSSETT SOUTH	DEVONIAN	69	8	86	114	10.8	32.0
TX	DOLLARHIDE	ELLENBUR	54	6	46	58	7.7	42.0
TX	DOLLARHIDE	CLEARFOR	102	9	102	137	11.3	20.0
TX	DOLLARHIDE	DEVONIAN	138	18	207	281	11.5	15.0
TX	DOLLARHIDE	SILVRIAN	180	22	206	294	9.4	47.0
TX	EMPEROR-DEEP	YATES-QU	80	10	60	76	6.0	88.0
TX	FLANNAGAN	CLEARFOR	85	11	84	110	7.6	12.0
TX	FULLERTON	8500	110	10	153	218	15.3	11.0
TX	G M K	SAN ANDR	43	6	45	56	7.5	41.0
TX	G-M-K, SOUTH	SAN ANDR	45	6	40	52	6.7	22.0
TX	GOLDSMITH	5600	863	91	1035	1427	11.4	11.0
TX	GOLDSMITH SA U	N SAN ANDR	233	20	278	395	13.9	12.0
TX	GOOD		119	13	164	225	12.6	11.0
TX	HUAT	CANYON	30	2	31	46	15.5	10.0
TX	I.A.B.	MENIELLE	44	5	49	66	9.8	13.0
TX	JORDAN	ELLENBUR	47	4	58	77	14.5	14.0
TX	KEYSTONE	SILURIAN	125	15	144	197	9.6	11.0
TX	KEYSTONE	ELLENBUR	262	28	187	253	6.7	26.0
TX	NEVA, WEST	STRAWN	39	4	43	59	10.8	19.0
TX	OCEANIC	PENNSYLV	59	5	93	128	18.6	39.0
TX	PECOS VALLEY	DEVONIAN	22	2	20	27	10.0	15.0
TX	PEGASUS	ELLENBUR	216	20	193	256	9.7	34.0
TX	REEVES	SAN ANDR	88	8	81	113	10.1	12.0
TX	ROBERTSON	CLEARFOR	195	13	160	229	12.3	35.0
TX	RUSSELL	CLEARFOR	209	20	245	339	12.3	22.0
TX	SAND HILLS	TUBB	468	59	403	553	6.8	21.0
TX	SAND HILLS	MCKNIGHT	626	74	602	761	8.1	40.0
TX	SEMINOLE	SAN ANDR	1353	163	1608	2221	9.9	14.0
TX	THREE BAR UNIT	DEVONIAN	129	14	145	196	10.4	15.0
TX	TXL	TUBB	191	24	186	251	7.8	23.0
TX	UNIVERSITY BLK	PENNSYLV	48	6	81	113	13.5	27.0
TX	UNIVERSITY BLO	C WOLFCAMP	50	3	41	56	13.7	10.0
TX	WASSON		3322	371	3514	4857	9.5	13.0
TX	YARBROUGH & AL	L ELLENBER	78	9	103	129	11.4	23.0
Total			**10953**	**1211**	**11800**	**16107**	**10.6**	**23.2**

Figure 11. Results of Preliminary Evaluation of Oil Fields Located in New Mexico

CO2 Results for WTI oil price = $25/bbl, with greater than 10% ROR

This is a TORIS Run assuming a constant price.

OOIP - Original Oil in Place
EOR - Oil Recoverable Due to CO2 Flooding
CO2-P - Purchased CO2 (Net CO2)
GR CO2 - Total CO2 Injected (Gross CO2)
RATIO - CO2 Purchased per Barrel of Oil Produced
ROR - Rate of Return assuming no inflation

STATE	FIELD NAME	RESERVOIR NAME	OOIP (MMBBLS)	EOR (MMBBLS)	CO2-P (BCF)	GR CO2 (BCF)	RATIO (MCF/STB)	ROR
NM	JUSTIS, NORTH	FUSSELMA	9	1	9	12	9.0	12.0
NM	DOLLARHIDE	ELLENBER	17	1	12	18	12.0	33.0
NM	TUBB	TUBB	22	5	32	43	6.4	27.0
NM	BRONCO	SILURO-D	31	3	21	27	7.0	76.0
NM	DOLLARHIDE	DEVONIAN	32	2	29	40	14.5	15.0
NM	MOORE	DEVONIAN	38	3	25	35	8.3	32.0
NM	PADDOCK	UPPER YE	49	5	48	64	9.6	10.0
NM	DOLLARHIDE	TUBB DRI	50	8	90	117	11.3	36.0
NM	BAGLEY	SILURO-D	55	6	44	55	7.3	37.0
NM	KEMNITZ	LOWER WO	57	12	73	97	6.1	30.0
NM	PADUCA	DELAWARE	63	5	78	110	15.6	31.0
NM	LOVINGTON	ABO	64	7	84	106	12.0	23.0
NM	SCARBOROUGH	YATES &	71	6	68	86	11.3	156.0
NM	CROSSROADS	DEVONIAN	90	11	96	122	8.7	72.0
NM	SAUNDERS	PERMO-PE	91	6	79	110	13.2	18.0
NM	PENROSE-SKELLY	QUEEN-GR	122	18	155	191	8.6	18.0
NM	EUNICE SOUTH	SEVEN RI	166	13	163	216	12.5	13.0
NM	JUSTIS	BLINEBRY	173	14	218	310	15.6	13.0
NM	VACUUM	GLORIETT	190	23	189	251	8.2	28.0
NM	EMPIRE	ABO	494	41	632	858	15.4	41.0
Total			**1884**	**190**	**2145**	**2868**	**10.6**	**36.1**

COAL-BASED INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

The coal-based integrated gasification combined cycle (IGCC) power plant used as the basis for this study was a market-based design developed by Parsons for evaluation of the market potential of advanced coal-fired power plants for the Electric Power Research Institute (EPRI) and U.S. Department of Energy (DOE)[9]. The baseline design (Case 3-E in Reference 9) centered on the use of a single combustion turbine coupled with a heat recovery system that generates steam for a single steam turbine generator. The gas turbine technology was based on General Electric's H-type advanced turbine system (ATS) machine. This particular machine features a gas turbine and steam turbine connected on a single shaft and generator.

A high-pressure Destec gasifier was chosen as the basis for that IGCC configuration. Raw fuel gas exiting the gasifier is cooled and cleaned of particulate before being routed to a series of water-gas shift reactors and raw gas coolers. These components convert CO present in the raw gas to CO_2; thereby concentrating it in the high-pressure raw fuel gas stream. Once concentrated, CO_2 can be removed during the desulfurization process through use of a double-staged Selexol unit. CO_2 is then dried and compressed to supercritical conditions for pipeline transport. In the IGCC design for the EPRI/DOE study, clean fuel gas from the Selexol unit, now rich in H_2, is fired in the combustion turbine, then expanded. However, to meet the anticipated SO_2 emissions standards for a power generation unit located in California, additional sulfur removal from the fuel is required before sending it to the combustion turbine. An H_2S polishing system consisting of a fixed-bed reactor with zinc oxide (ZnO) as the reagent was added to the IGCCs used as the basis for this study. Waste heat is recovered from combustion turbine exhaust and used to raise steam to feed to a steam turbine. To meet the more stringent NOx emissions standards anticipated in California, an SCR NOx removal system, not incorporated in the EPRI/DOE study, was added to the IGCCs downstream of the waste heat recovery system for this study.

H_2S polishing and SCR NO_x removal systems were incorporated into IGCC+S plants at both the San Joaquin Valley and the Four Corners locations.

<u>IGCC Plant Performance</u>

The performance of the baseline IGCC power plant developed for the EPRI and U.S. DOE study was based on mid-USA ambient conditions and use of an Illinois No. 6 coal as the fuel. These performance data were adjusted for this study to take into account the effects of the different coal properties associated with a Powder River Basin (PRB) coal (Wyodak coal) and the ambient conditions in the Four Corners region of New Mexico and the San Joaquin Valley in California.

The thermal performance characteristics of the IGCC plants located in the Four Corners region of New Mexico and the San Joaquin Valley, California, are compared with the performance characteristics of the baseline Case 3-E mid-USA plant in Figure 12. Also shown are IGCC plants without the sequestration.

Figure 12. IGCC+S Plant With CO_2 Capture Performance Comparison

	IGCC+S Baseline Case 3-E[9]	IGCC+S San Joaquin Valley, CA	IGCC+S Four Corners, NM	IGCC only San Joaquin Valley, CA	IGCC only Four Corners, NM
Coal	Illinois #6	Wyodak PRB	Wyodak PRB	Wyodak PRB	Wyodak PRB
Turbo-Set Power Output, kW	465,474	465,474	386,343	474,029	393,444
Fuel Gas Expander Power, kW	8,801	8,801	7,305	0	0
Gross Power Output, kWe	474,275	474,275	393,648	474,029	393,444
Auxiliary Power					
Coal Handling & Grinding, kW	1,190	1,600	1,330	1,430	1,190
Slag Handling & Dewatering, kW	160	130	110	120	100
Gas Cleanup, kW	8,690	3,200	2,680	2,890	2,420
HP CO_2 Compressor, kW (Note 1)	26,850	27,770	23,050	0	0
Balance of Auxiliary Power, kW	53,250	53,250	41,900	39,840	30,770
Total Auxiliary Power, kWe	90,140	85,950	69,070	44,280	34,480
Net Power Output, kWe	384,135	388,323	324,580	429,750	358,970
Heat Rate, Btu/kWh HHV	9,705	9,600	9,533	7,780	7,730
Net Plant Efficiency	35.2% HHV 36.8% LHV	35.6% HHV 37.4% LHV	35.8% HHV 37.7% LHV	43.9% HHV 46.3% LHV	44.2% HHV 46.5% LHV
Coal Feed, 10^6Btu/h	3,728	3,728	3,094	3,343	2,775
Coal Feed, lb/h	319,560	431,980	358,543	387,410	321,550
Ash/Slag Production, lb/h	31,811	25,055	20,796	22,470	18,650
Sulfur Production, lb/h	7,989	2,582	2,143	2,316	1,922
CO_2 Produced from Coal, lb/h	746,972	791,963	657,329	710,252	589,509
CO_2 Captured @ 90%, lb/h	681,404	712,767	591,596	0	0
CO_2 Emissions, lb/h	65,568	79,196	65,733	710,252	589,509

Note 1 – Final CO_2 pressure of 2,200 psia
PRB = Powder River Basin

The high elevation (5,333 ft above sea level) of the Four Corners region of New Mexico will significantly reduce the power output from and fuel requirement for the IGCC plant relative to the mid-USA Case 3-E baseline plant design. The estimated changes are based on General Electric Power performance guidelines.[10] The lower ambient pressure reduces the air density, thus reducing the mass flow of air that can be introduced into the gas turbine. This in turn means that less fuel can be introduced, thus reducing the total thermal energy input and power output. The result is a decrease in fuel input and net power output of about 17%.

EXCEPTIONAL IGCC+S PLANT ENVIRONMENTAL CLEANLINESS

The operation of a modern, state-of-the-art gas turbine fueled by coal-derived synthesis gas generated with an oxygen-blown E-Gas™ gasifier is projected to result in very low levels of SO_2, NOx, and particulate emissions. Also, the inclusion of a CO_2 removal system greatly decreases the ambient release of CO_2 from the power plant.

Current California Environmental Protection Agency Air Resources Board and San Joaquin Valley Unified Air Pollution Control District rules and guidelines do not specifically address emissions from coal gasification combined cycle power generation plants. Personnel in these agencies indicate that it is likely that an IGCC plant with an output on the order of 400 MWe would have to meet the Air Resources Board (ARB) guidelines based on the best available control technology (BACT) for natural gas-fired gas turbines used for combined-cycle power generation.[11] The summary of the ARB's BACT for the control of emissions from stationary gas turbines used for combined-cycle power plant configurations is shown in Figure 13.[12] The emissions of primary concern with respect to the IGCC+S plant are SO_2, NOx, and PM_{10}. The levels of CO and VOC are expected to be no greater than those of natural gas-fired gas turbines. The ARB's SO_2 emissions standard is based on a gas turbine being fired on natural gas having a fuel sulfur content of no more than 1 grain/100 scf. The NOx standard was based on the use of dry low-NOx combustors and selective catalytic reduction (SCR).[13] The current 1-hour rolling average NOx standard may be reduced to 2.0 ppmvd in the near future. The PM_{10} standard was based on achieving control through combustion of low-sulfur natural gas (less than 1 grain/100 scf) along with combustion design that minimizes NOx and unburned hydrocarbons.[14]

Figure 13. California Environmental Protection Agency Air Resources Board Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations

Source: Reference 12

NO_x	CO	VOC	PM_{10}	SOx
2.5 ppmvd @ 15% O_2, 1-hour rolling average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per 10^6Btu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100scf (no more than 0.55 ppmvd @ 15% O_2)

Figure 14. NOx, SO_2, and CO_2 Emissions from IGCC+S in San Joaquin Valley With and Without the Addition of H_2S Polishing and SCR NOx Control

With H_2S Polishing and SCR NOx Control			
	NOx	**SO_2**	**CO_2**
ppmvd @ 15% O_2	<1	<0.1	7,405
lb/10^6 Btu	<.01	<.001	21.2
lb/MW-h	<0.03	<.01	0.20
Without H_2S Polishing or SCR NOx Control			
ppmvd @15% O_2	10	1.6	7,405
lb/10^6 Btu	0.03	0.007	21.2
lb/MW-h	0.3	0.07	0.20

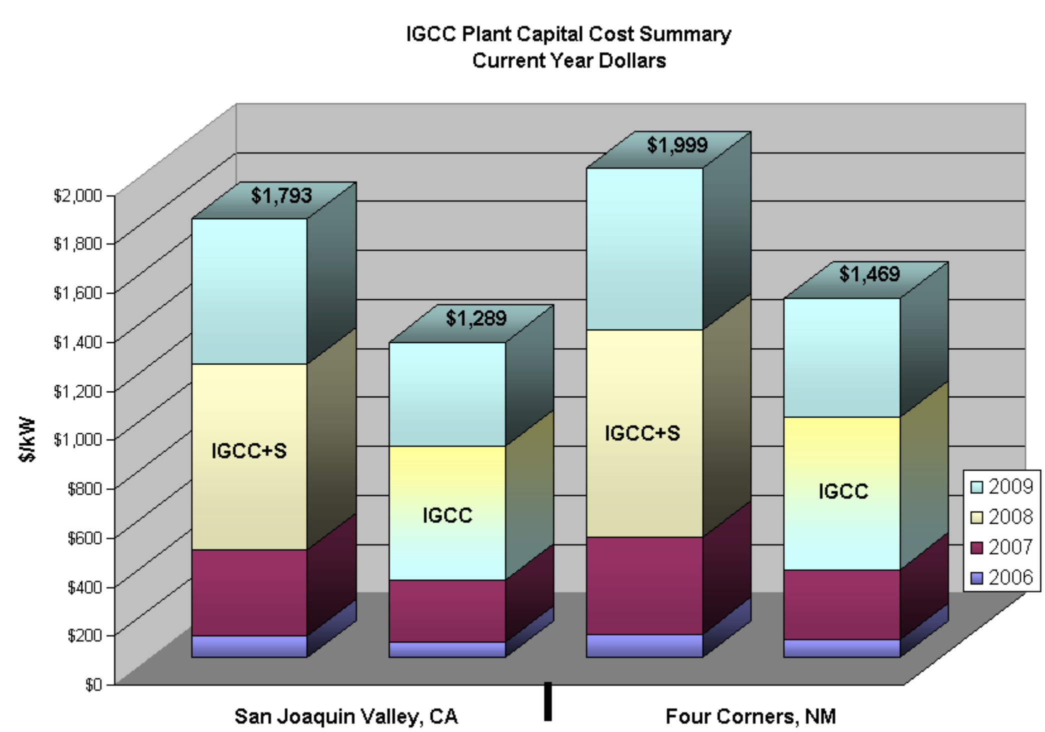
To meet ARB's stringent standards this IGCC+S plant was upgraded from the base design concept from the configuration selected by Parsons for the EPRI/DOE study.[9] To meet the ARB's SO_2 and NOx standards, the evaluators added a fixed-bed H_2S polishing system using ZnO as the reagent to the configuration upstream of the gas turbine for added SOx control, and an SCR was added downstream of the heat recovery system for added NOx control. These add cost to the units, but result in an exceptionally clean plant. The expected emissions prior to and after the addition of the H_2S polishing system and SCR NOx control system are shown in Figure 14. The H_2S concentration in the syngas from the Selexol system is reduced from about 30 ppmv to about 1 ppmv at the exit of the polishing system, resulting in a sulfur concentration in the gas to the gas turbine of less than 0.1 grains/100 scf. The SO_2 concentration in the flue gas would be less than 0.1 ppmvd @ 15% O_2, significantly lower than the ARB's standard. The SCR NOx control system reduces the NOx emissions to about 1 ppmvd @ 15% O_2, also significantly below the ARB's standard. At this low level of sulfur in the syngas, PM_{10} emissions are also expected to be low.

IGCC AND IGCC+S PLANT COSTS

The capital and O&M costs for the systems comprising the IGCC+S plants located in the San Joaquin Valley in California and Four Corners region of New Mexico were estimated based on cost estimates previously developed by Parsons and others under other studies for similar systems in other locations. The costs for all systems except the H_2S polishing and SCR NOx control systems were estimated by adjusting the cost estimates developed for the EPRI/DOE study in Reference 9 based on the differences in performance characteristics presented in Figure 12. The capital and fixed O&M cost estimates for the H_2S polishing system were based on cost estimates developed by Parsons for mercury removal in an IGCC plant by a fixed carbon bed system that would be similar to a fixed ZnO bed H_2S removal system[15]. The variable consumable operating costs were developed based on the cost of the ZnO reagent. The cost estimates for the SCR NOx control system were based on costs developed by Parsons for an SCR NOx control system for a commercial client on the east coast of the United States.

The unit capital cost estimates in current-year dollars per kilowatt for IGCC plants located in the San Joaquin Valley in California and the Four Corners region of New Mexico, with and without CO_2 removal, are summarized in the chart in15. The unit fixed and variable O&M costs were also estimated.

Figure 15. IGCC Plant Capital Cost Summary (Current Year $/kW)



The addition of the H_2S polishing and SCR NO_x control systems to meet the emissions standards in California increases the plant capital cost estimate by about 2.4%. It should again be noted that H_2S polishing and SCR NO_x control systems are incorporated into both the San Joaquin Valley and Four Corners IGCC plants. It should also be noted that although the absolute capital cost of the IGCC+S in the San Joaquin Valley is slightly higher than in the Four Corners region, the unit capital cost in dollars per kilowatt, as shown in Figure 15, is lower because of the higher net power generation of the San Joaquin Valley plant.

IGCC Plant Operating and Maintenance Costs

The operating and maintenance (O&M) costs are separated into two types, fixed and variable. Details of their estimation are given in[2]. The addition of the H_2S polishing and SCR NOx control systems increases the fixed O&M cost estimate by about 1.6% and the variable O&M cost estimate by about 9.1% compared to a conventional IGCC plant.

Cost of CO_2 Capture

To evaluate the cost of CO_2 capture, the performance and capital and O&M costs of IGCC plants without CO_2 capture located in the Four Corners region of New Mexico and the San Joaquin Valley, California, were also estimated using the same methodology as used for the IGCC+S plants. Details are given in the project report.[2] For the San Joaquin Valley IGCC plant, the increase in capital cost for CO_2 removal is estimated to be about 26%, and the increases in fixed O&M costs and variable O&M costs are estimated to be about 17% and 13%, respectively. For the Four Corners IGCC plant, the increase in capital costs for CO_2 removal is estimated to be about 23%, and the increases in fixed O&M costs and variable O&M costs are estimated to be about 11% and 12%, respectively.

CO_2 Transport Assessment

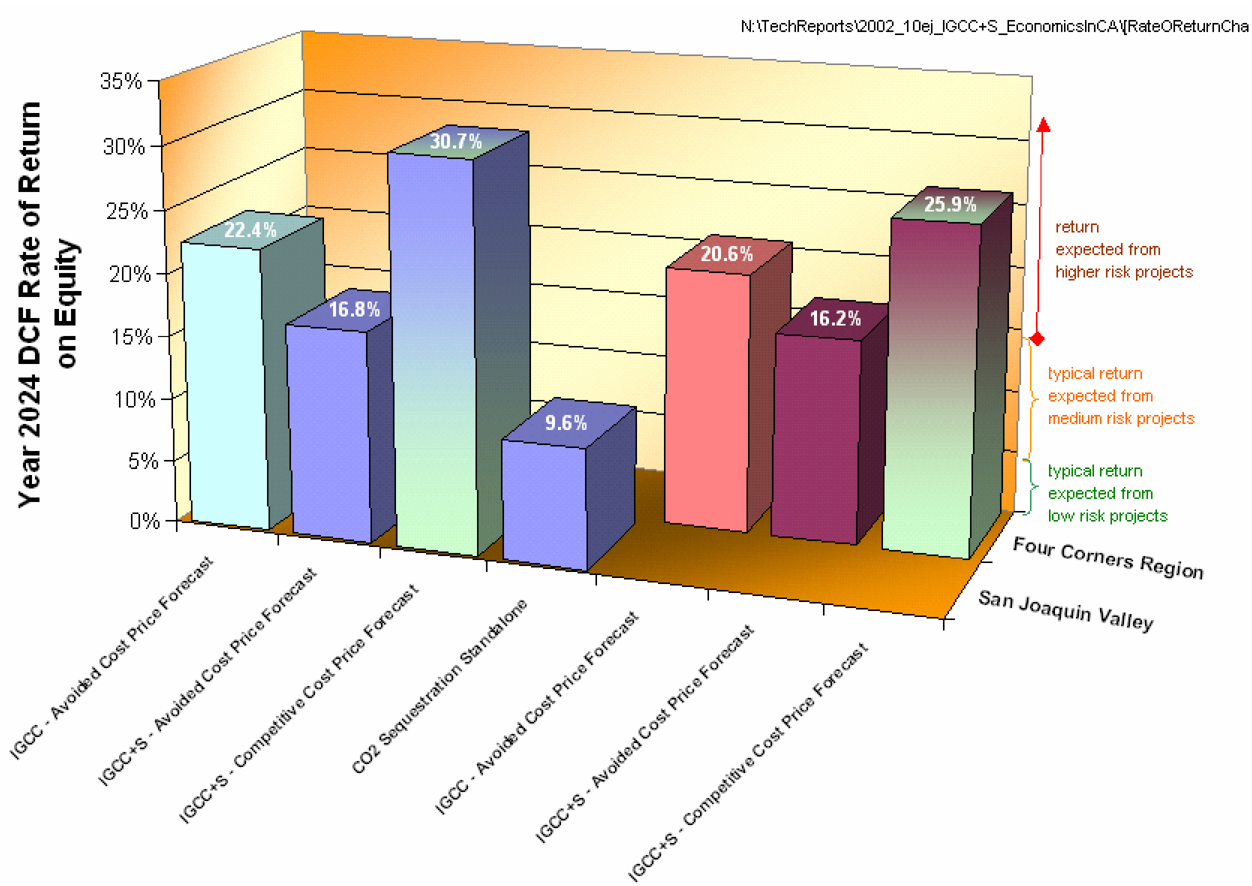
The cost to transport CO_2 from the IGCC+S plant to oil fields for use in enhanced oil recovery (EOR) was assessed for two cases. One case transports CO_2 from an IGCC+S plant in the Four Corners Region of New Mexico to oil fields in the San Joaquin Valley in California. The other case transports the CO_2 from an IGCC+S plant in the San Joaquin Valley to local oil fields. The cost assessments were performed using the Massachusetts Institute of Technology (MIT) Pipeline Transport Model, developed by the MIT Energy Laboratory.[16] Details are given in[2]. Transportation costs were relatively small components of both capital and operating costs for all Cases considered. This is due to the assumed close proximity of power plant to oil fields for the San Joaquin Valley location, and the access to an existing CO_2 pipeline network for the Four Corners location.

FINANCIAL RESULTS

Figure 16 gives the expected financial returns calculated for the various cases investigated. In all cases the returns, done on a current year basis for 2024, on a cumulative basis for the project, and on a discounted cash flow (DCF) basis indicate that the projects are overwhelmingly financially viable.

Figure 16. Summary of the Rate of Return on Equity

Case	Title	Current	Cumulative	DCF
A	IGCC+S Avoided Cost Pricing - San Joaquin Valley	26.83%	354.44%	16.82%
B	IGCC Avoided Cost Pricing - San Joaquin Valley	37.44%	483.60%	22.44%
C	IGCC+S Competitive Pricing - San Joaquin Valley	55.84%	712.58%	30.68%
D	IGCC+S Avoided Cost Pricing - Four Corners Region	26.41%	344.31%	16.24%
E	IGCC Avoided Cost Pricing - Four Corners Region	34.54%	441.53%	20.58%
F	IGCC+S Competitive Pricing - Four Corners Region	46.22%	582.93%	25.92%
G	CO_2 Sequestration Standalone - San Joaquin Valley	13.67%	215.63%	9.56%



<u>Graphical Summary of Results</u>

For each case evaluated, the following exhibits present the Construction Costs per year, and then the revenues and expenses for each case.

Figure 17. Case A – IGCC+S San Joaquin Valley (Avoided Cost Pricing)

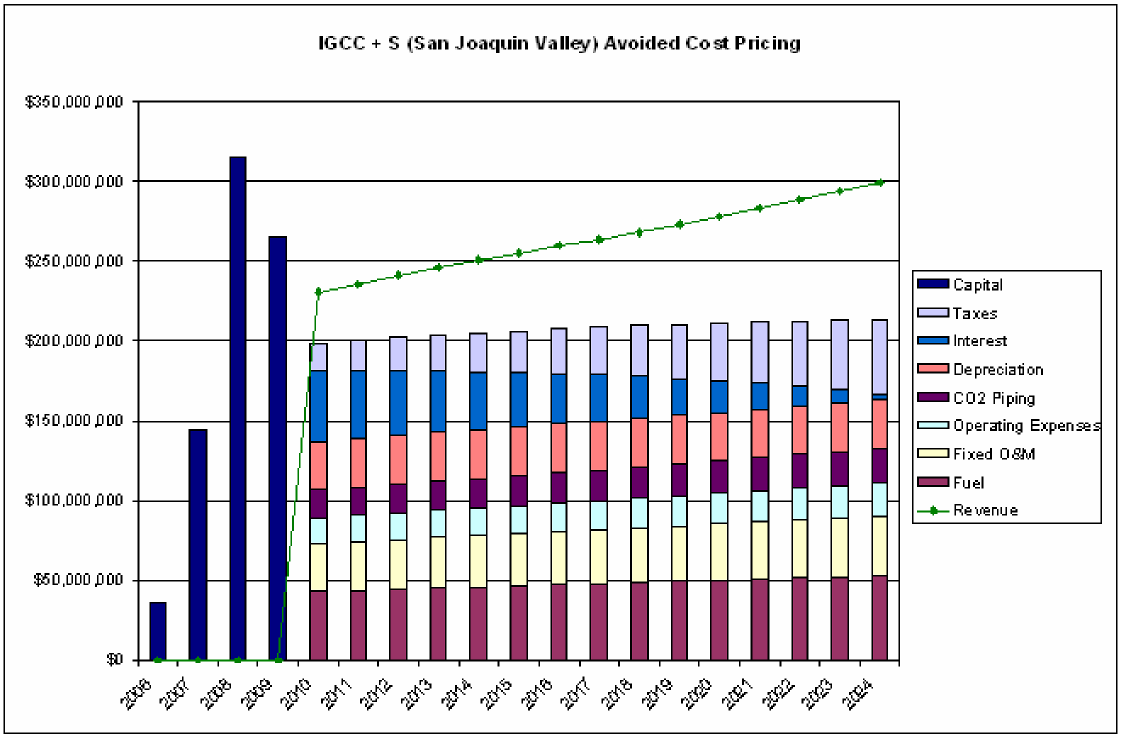


Figure 18. Case B – IGCC San Joaquin Valley (Avoided Cost Pricing)

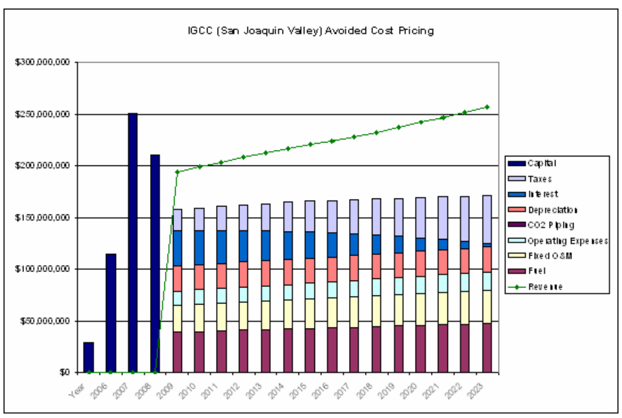


Figure 20. Case D – IGCC+S Four Corners Region (Avoided Cost Pricing)

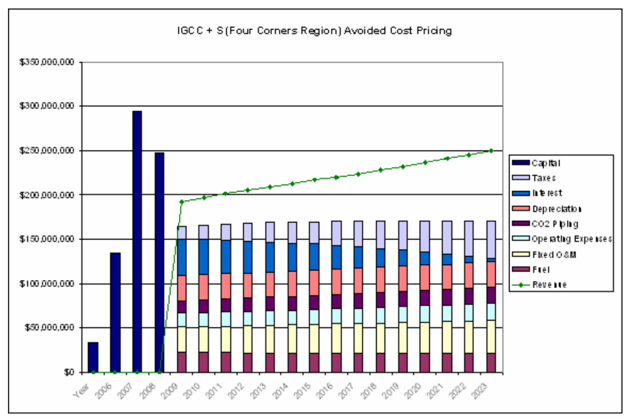


Figure 19. Case C – IGCC+S San Joaquin Valley (Competitive Pricing)

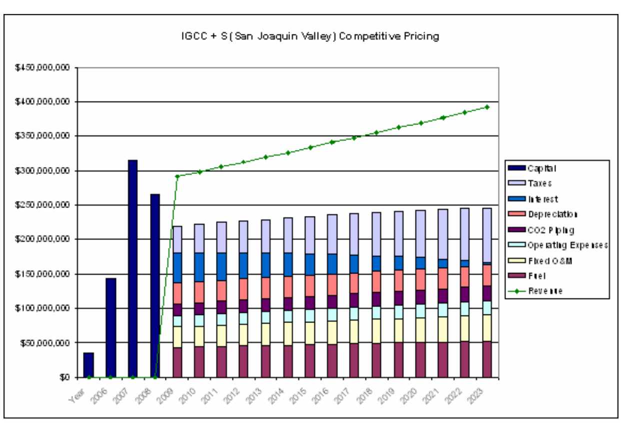


Figure 21. Case E – IGCC Four Corners Region (Avoided Cost Pricing)

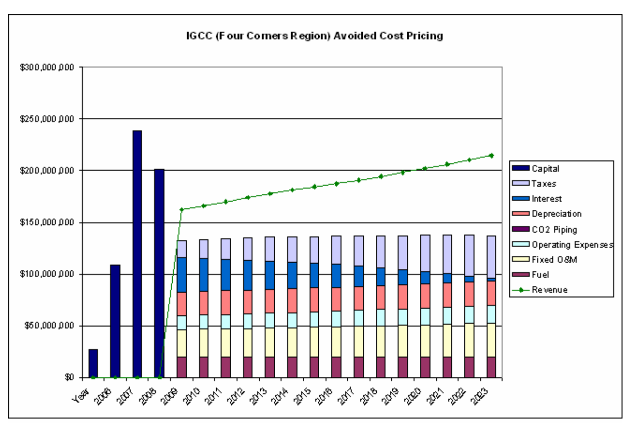


Figure 22. Case F – IGCC+S Four Corners Region (Competitive Pricing)

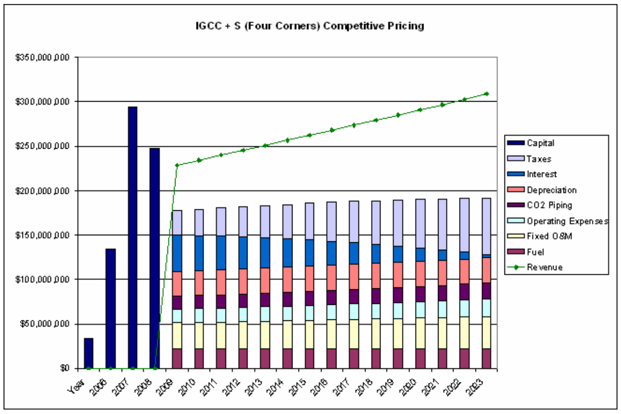
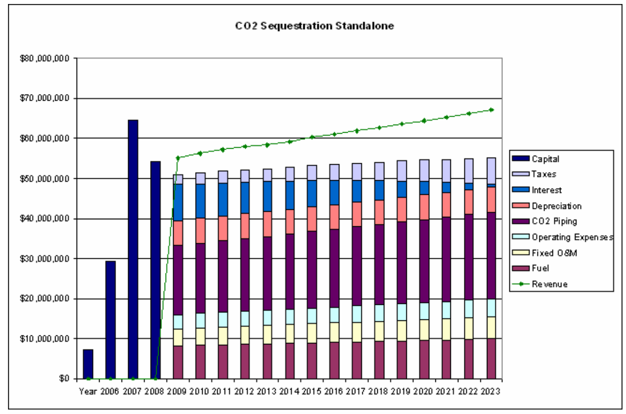


Figure 23. Case G – CO2 Sequestration Standalone



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[14] California Environmental Protection Agency Air Resources Board Stationary Source Division. Guidance for Power Plant Siting and Best Available Control Technology. As approved by the Air Resources Board on July 22, 1999. Issued September 1999. Pg. 33.

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