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Final Report

GEMSET Special Assessment:

Coal-Based Power Generation for California with CO_2 Removed for Use in Enhanced Oil Recovery

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System & Policy Support

Technical Report Abstract

EJ-2002-10

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

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Estimates show that a coal-based integrated gasification combined cycle (IGCC) with CO_2 capture and sequestration (+S) would yield only one-fifth the specific carbon emissions (lb CO_2 /kWh) as would state-of-art natural-gas-fueled combined cycle (NGCC). California appears to be a good venue for consideration of a coal-based IGCC+S power plant because:

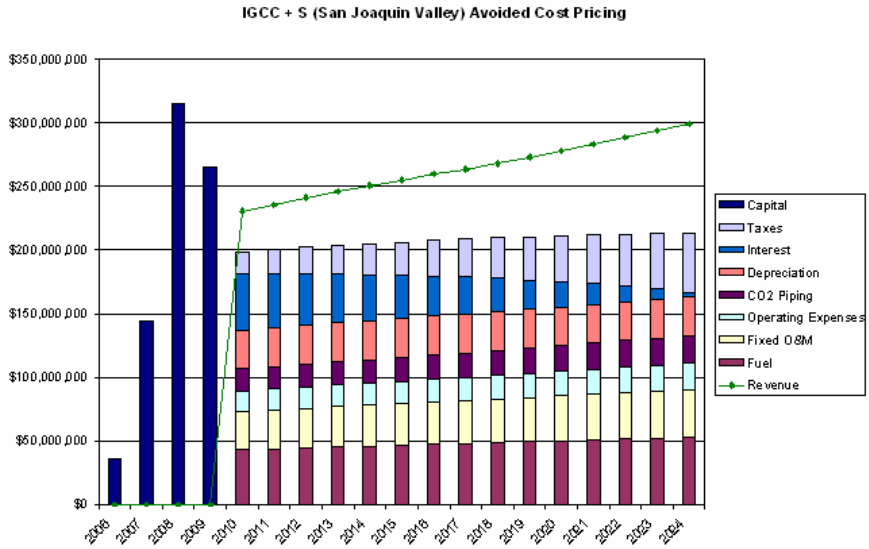
(1) There is a critical need for additional diversity in California's baseload generating capacity,

(2) Electric prices there are among the highest in the U.S., and

(3) There is an unserved market for CO_2 recovered from the plant that could be used to enable enhanced oil recovery from nearby oil fields.

The U.S. Department of Energy National Energy Technology Laboratory (NETL) Office of System & Policy Support therefore posed the question: "What are the financial merits of an IGCC+S plant serving the California electric market?"

Based on the assumptions contained within this evaluation, a coal-based IGCC+S power plant in California would generate an Internal Rate of Return (IRR) to its owners over 17% during the 15-year period of the outstanding debt. The project is estimated to provide over $700 million in cash to the equity investors, three times what they invested.



Parsons Report No. EJ-2002-10
Report Title:

Coal-Based Power Generation for California with CO_2 Removed for Use in Enhanced Oil Recovery (EOR)

Key Services

- Characterize all California units
- Estimate how California electric price would change under different fuel cost scenarios
- Evaluate characteristics of the IGCC+S versus gas turbines and combined cycles of various sizes
- Estimate economics and financing of the IGCC+S under the various scenarios
- Characterize the potential market for any CO_2 removed from the IGCC by the sequestration system for use to enhance the recovery of oil for several scenarios

Study Regions

California generating units and electric market

California and Four Corners IGCC sites

California and Texas markets for CO_2 for enhanced oil recovery

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Significance

The money needed to buy a coal-based integrated gas turbine combined cycle with CO_2 removal for electric power generation is substantial. An owner might risk over a half-billion dollars to build a 390 MW IGCC+S plant to meet electric needs.

When making a decision about an investment approaching more than half of a billion dollars, great care must be taken to ascertain the potential costs and revenue streams for the unit and the potential exposures to technical and financial risks. This report is the first step in what must properly be a very carefully reviewed path toward implementation of such a project. This feasibility screening evaluation shows that there is good expectation there will be acceptable financial return to an owner. This justifies the need for the next step: a more thorough conceptual design evaluation to better substantiate the technical and cost assumptions.

Approach

The GEMSET Team evaluated 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 sent to enhance the oil recovery from California oil fields;
- Outside California, in the Four Corners region of New Mexico, with the electric load serving California, and the CO_2 sent by existing pipeline to Four Corners and Texas oil fields; and,
- Outside California, in the Four Corners region of New Mexico, with the electric load serving California, and the CO_2 sent by a new pipeline to the San Joaquin Valley.

Either the San Joaquin or Four Corners location affords a good market for electricity sales to California, and for the use of the captured CO_2 product. However, only the first two choices have good financial return.

For the third choice, the capital and O&M costs associated with transportation of the CO_2 removed from the IGCC plant located in New Mexico to the San Joaquin Valley oil fields were estimated using the Massachusetts Institute of Technology's Pipeline Transport Model. Based on that assessment, the third choice, building a new CO_2 pipeline to California oil fields, was not attractive financially, so this choice was dropped and the study focused on the merits of the first two options.

The time period set for the evaluation is for an IGCC+S system entering the market in 2010. To do this, the project would have to begin in 2006 so the unit could enter service in 2010. The technology level used for the IGCC+S plant that could be available in this time frame is one that was established by Parsons for a study for the U.S. Department of Energy and EPRI that assessed the performance and economics of IGCC+S technology. This task scaled that IGCC+S design to this study's locations, and used the GEMSET market

evaluation system for the California electric market assessments.

This study was based upon the 2010 through 2020 natural gas and coal price forecasts for California and for New Mexico that were developed in the GEMSET 2002 Fuel Price Characterization. That forecast is based on FERC Form 423 delivered prices, NYMEX energy closings, NYMEX futures trading, and for the longer term projections, EIA NEMS fuel price escalation rates.

Some features of this study include the following:

- The capital costs of IGCC and IGCC+S plants in the San Joaquin Valley, California, and Four Corners region of New Mexico were estimated.
- Permitting a coal-fueled plant in the State of California is expected to require an exceptionally effective combination of environmental control equipment to meet the stringent regulations there. The IGCC plants sited both in the San Joaquin Valley and Four Corners locations each were assessed with sophisticated environmental cleanup equipment, including H_2S polishing and SCR NO_x control systems, that are expected to allow the units to operate with very low environmental emission levels. The IGCC+S systems evaluated here had equipment included to provide expected exhaust emissions similar to those from natural-gas-fueled combined cycles that are now being permitted in California.
- The production costs of IGCC, IGCC+S, and natural gas combined cycle (NGCC) plants serving the California electric market were estimated. In addition, the expected production costs of each of the 1,423 generating units presently in the state, and those expected to be added during the study timeframe were also characterized.
- A sophisticated evaluation method characterized California's hour-by-hour electric price in year 2010 and 2020 using GEMSET generating fleet stacking methods to estimate electric price, revenue from electric sales, and the expected IGCC+S unit dispatch and capacity factor.
- The potential hour-by-hour sale price of electricity was evaluated as it was affected by the entire fleet of units projected to be operating in the California region in 2010. The amount of time a unit would be called on for operation was assessed, and the potential income to the generating unit owner evaluated.

Results

The sophisticated assessment needed to evaluate the expected financial prospects of this type of project is described in this report. The report gives an in-depth evaluation of results from both a technical and financial viewpoint.

Based on the assumptions made in those areas, this project would generate substantial financial returns under the conservative assumptions made in this investigation.

The coal-based IGCC+S described here would make economic sense, and should be more thoroughly investigated.

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Abbreviations and Acronyms

Term	Meaning
AAGC	average automatic generation control
ACAP	available capacity (as in PJM West)
AEO1999	EIA Annual Energy Outlook 1999
AEO2000	EIA Annual Energy Outlook 2000
AEO2001	EIA Annual Energy Outlook 2001
AEO2002	EIA Annual Energy Outlook 2002
AEP	American Electric Power
AGC	automatic generation control
ALM	Active Load Management
ARB	Air Resources Board
ASCC	Alaska Systems Coordinating Council
AVR	automatic voltage regulator
BACT	best available control technology
Bcf	billion cubic feet, that is, 10^9 cubic feet
Block Forwards Market	a continuously traded standardized product for month-ahead on-peak energy in blocks of 1 or 25 MW
BME	balancing market evaluation
CAISO	California Independent System Operator
CalPX	California Power Exchange (no longer operating)
Capacity Resource	Generator qualifying as PJM capacity
CARL DATA	control area resource and load data submitted by Control Area Resources to the ISO
CDR	Capacity Deficiency Rate
COE	the cost of electricity, the levelized busbar cost of electric production including amortized capital, operating, and maintenance costs
combustion turbine, CT	a synonym for gas turbine, used interchangeably
ComEd	Commonwealth Edison
CP&L	a Progress Energy company
CR	competitive retailer
CSC	commercially significant constraint
DAM	day-ahead market
Day-Ahead Market	functions as a physical forwards market and establishes the supply and demand for electric power in California one day in advance of delivery
Day-Of Market	provides for three auction periods daily, 6 a.m., noon, and 4 p.m.
DCA	Department of Community Affairs

DEP ..... Department of Environmental Protection
DMNC ..... dependable maximum net capability
DNI ..... desired net interchange
DOE ..... United States Department of Energy
DSM ..... demand side management
ECAR ..... East Central Area Reliability Coordination Agreement, a NERC region
EDC ..... Electric Distribution Company
EFORd ..... demand equivalent forced outage rate
eGADS ..... electronic generating availability data system; an electronic data system allowing the posting of data regarding a generating unit's availability record
EIA ..... the Energy Information Administration of the DOE
EOR ..... enhanced oil recovery
EPA ..... U.S. Environmental Protection Agency
EPAct ..... Energy Policy Act of 1992
EPRI ..... Electric Power Research Institute
ERCOT ..... Electric Reliability Council of Texas, a NERC region
ERO ..... industry self-regulatory electric reliability organization
EUE ..... expected unserved energy
FERC ..... Federal Energy Regulatory Commission
FGD ..... flue gas desulfurization, a sulfur emission control device
FGT ..... Florida Gas Transmission, a natural gas transportation pipeline company
FLOASIS ..... Peninsular Florida's OASIS
FOB ..... free on board
FPC ..... Florida Power, a Progress Energy company
FPL ..... Florida Power & Light Company
FPSC ..... Florida Public Service Commission
FRCC ..... Florida Reliability Coordinating Council, a NERC region
FTR ..... Financial Transmission Right
GADS ..... generating availability data system; see "eGADS"
gas turbine, GT ..... a synonym for combustion turbine, used interchangeably
GEMSET ..... government energy market segment evaluation tool
GNP ..... gross national product
GT ..... gas turbine (a synonym for combustion turbine)
GTCC ..... natural gas fueled gas turbine combined cycle
HAM ..... hour-ahead market
HHV ..... higher heating value of a fuel including the heat released if all of the water vapor in the combustion products were condensed
HRSG ..... heat recovery steam generator
ICAP ..... installed capacity requirement
IGCC ..... integrated gasification combined cycle

IGCC + S.....integrated gasification combined cycle with CO_2 sequestration
IOU.....investor-owned utility
IPD.....implicit price deflator
IPM.....the EPA's integrated planning model
IPP.....an independent power producer, an unregulated electric generating company
IRM.....installed reserve margin
IRP.....integrated resource plan
ISO.....independent system operator; a regulated body that dispatches all competitive electric generation on the high voltage transmission grid within its service region; they operate the grid, administer the power pools power transfers, select the lower cost generation bid into the pool according to the pool's operating rules, and maintain the integrity of the electric transmission grid
ISONE.....New England ISO
ITC.....Independent Transmission Company
JEA.....Jacksonville Electric Authority
KUA.....Kissimmee Utility Authority
LAK.....City of Lakeland
LBMP.....locational-based marginal pricing
LCC.....local control center
LHV.....lower heating value of a fuel, the heat released if all of the water vapor in the combustion products remained as steam
LMP.....locational marginal price
LOC.....lost opportunity cost
LOLE.....loss of load expectation
LOLP.....loss of load probability
LSE.....load-serving entity
MAAC.....Mid-Atlantic Area Council, a reliability council, a NERC region
MAIN.....Mid-America Interconnected Network, a NERC region
MAPP.....Mid-Continent Area Power Pool, a NERC region
MCP.....market clearing price
MCPC.....market clearing price for capacity
MCPE.....market clearing price for energy
MCR.....maximum continuous rating
MISO.....Midwest Independent System Operator
mmBtu.....10^6 British thermal units
MMC.....market monitoring committee
MMU.....Market Monitoring Unit
MOU.....Memorandum of Understanding
MVA.....megavolt amperes
MVAR.....megavolt-ampere-reactive

MWe ..... electrical megawatts

MWth ..... thermal megawatts

NAERO ..... the North American Electric Reliability Organization; NERC is in the process of transforming itself into NAERO, whose principal mission will be to develop, implement, and enforce standards for a reliable North American bulk electric system. (NERC has no enforcement capability.)

NEL ..... net energy for load

NEMS ..... the EIA's national energy modeling system

NERC ..... North American Electric Reliability Council; soon, NERC, without enforcement authority, will become NAERO with that authority

NERTO ..... North East Regional Transmission Owner

NETL ..... the U.S. Department of Energy's National Energy Technology Laboratory

NOIE ..... Non-Opt-In Entity

NOPR ..... notice of proposed rulemaking

NOx ..... nitrogen oxides, types of air pollutant, mainly NO and NO_2

NPCC ..... Northeast Power Coordinating Council, a NERC region

NPTO ..... National Petroleum Technology Office

NPV ..... net income present value

NSPS ..... New Source Performance Standards

NUG ..... non-utility generator, a competitive, unregulated independent electric power producer

NYCA ..... New York Control Area

NYISO ..... the New York State independent system operator, a NERC region

NYMEX ..... New York Mercantile Exchange

NYPA ..... New York Power Authority

NYPP ..... New York Power Pool

NYSRC ..... New York State Reliability Council

O&M ..... operation and maintenance

OASIS ..... open-access same-time information system

OATT ..... open access transmission tariff

OI ..... PJM Office of the Interconnection, LLC

OTAG ..... Ozone Transport Assessment Group

OTR ..... Northeast Ozone Transport Region

OUC ..... Orlando Utilities Commission

P.E. ..... licensed professional engineer

PCD ..... particulate emission control device

PECO ..... Philadelphia Electric Company

PJM ..... Pennsylvania, New Jersey, Maryland, or PJM Interconnection LLC, an ISO/RTO

PPL ..... Pennsylvania Power & Light Company

PRB ..... Powder River Basin

PRL ..... price responsive load
PSC ..... local state Public Service Commission
PSE&G ..... Public Service Electric & Gas Company
PUCT ..... Public Utility Commission of Texas
PUHCA ..... Public Utilities Holding Company Act
PURA ..... Public Utility Regulatory Act
PURPA ..... Public Utility Regulatory Policy Act of 1978
RACT ..... reasonably available control technology (pollution control)
RAG ..... Reliability Assessment Group
REP ..... retail electric provider
RMCP ..... regulation market clearing price
RTEM ..... real-time energy marketplace
RTO ..... regional transmission operator
RWG ..... Resource Working Group
SAS ..... Statement on Auditing Standards
SCD ..... security-constrained dispatch
SCNG ..... Strategic Center for Natural Gas
SCR ..... selective catalytic reduction
SCUC ..... security-constrained utility commitment
SERC ..... Southeast Electric Reliability Council, a NERC region
SMCP ..... spinning market clearing price
SMD ..... FERC's Standard Market Design for competitive electric markets
SOx ..... sulfur oxides, types of air pollutant, mainly SO_2
SPP ..... Southwest Power Pool, a NERC region
SRE ..... supplemental resources evaluation
State Estimator ..... PJM system model
SWG ..... Stability Working Group
TAC ..... Technical Advisory Council
TCC ..... Transmission Congestion Contracts
TCR ..... Transmission Congestion Right
TDSP ..... Transmission and/or Distribution Service Provider
TECO ..... Tampa Electric Company
TIS ..... Texas Interconnected System
TWG ..... Transmission Working Group
TYSP ..... 10-year site plan
UDI ..... Utility Data Institute
VAR ..... volt-ampere-reactive
WECC ..... Western Electricity Coordinating Council (formerly WSCC), a NERC region
WTI ..... West Texas Intermediate

1. Conclusions, and Summary of the Study Approach

Background. This is a report about the economic and financial viability of a coal-based integrated gasification combined cycle (IGCC) 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 the CO_2, eliminating it as a greenhouse gas. Such a plant is referred to as an "integrated gasification combined cycle with CO_2 sequestration," more easily referred to here by its acronym: "IGCC+S."

This evaluation used competitive market evaluation experts to develop solidly based conjecture about how future fuel price changes and potential future generating fleet configurations might affect electric prices in the California region. A thorough assessment of the more than 1400 generating units in California was developed, and the fuel consumption and economics of this fleet were characterized. This allowed the development of a stacking order for the units on the basis of their present operating cost circumstances. The altered threshold bid prices for the fleet under the several fuel price scenarios allowed the re-stacking of this threshold bid price order.

The GEMSET Team analyzed California's expected future electric price structure, and then developed a projection of the potential return to investors from electric sales. From this, the nature of the competitive market was inferred. A sophisticated model of the region was established that then allowed a reasoned conjecture about how the price structure of California might change under differing demand and fuel price circumstances. This allowed the projection of electricity price, and assessment of the potential financial income and capacity factor of a unit that hoped to compete for electric sales within the California region.

Using this evaluation, the GEMSET Team estimated the prices and capacity factors that would be expected under each scenario's particular circumstances. This established a basis for assessing how each scenario's circumstance might influence the economics of gas turbines and combined cycles versus the economics of potential competing new IGCC+S or IGCC power plant projects.

Conclusions. California appears to be a good location to consider building an IGCC+S:

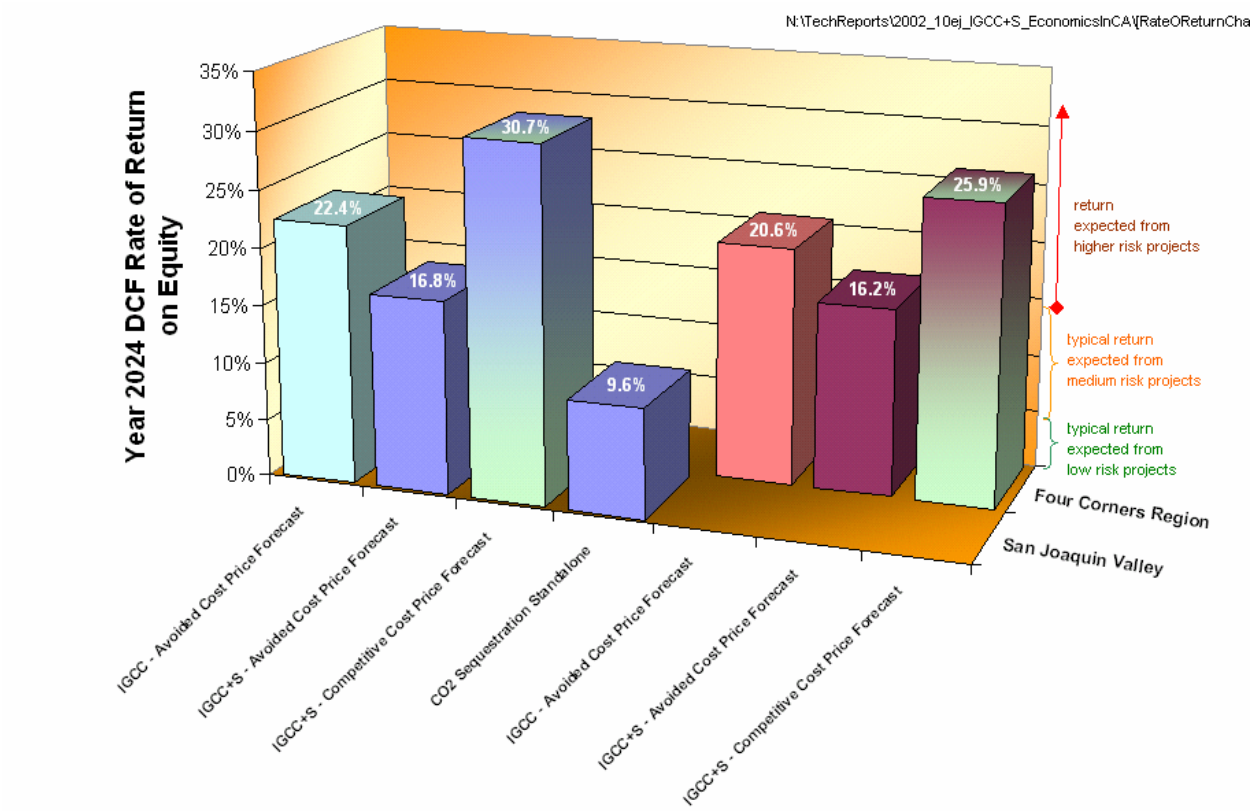
- There is a critical need for additional diversity in California's baseload generating capacity,
- Electric prices are among the highest in the U.S., and
- There is an unserved market for CO_2 recovered from the plant that could be used to enable enhanced oil recovery from nearby oil fields.

Locating a coal-fueled power plant in California would be a daunting licensing problem, as the State of California environmental regulators have long been averse to locating coal plants within their borders. However, if the plant were clean enough, the ability to site such a coal plant would be an incredible benchmark for the coal power industry. In this evaluation, each coal-fired unit was supplied with highly efficient environmental control equipment that added cost, but gives these units environmental emission levels equivalent to those of a natural-gas-fueled combined cycle.

Still, since licensing a new coal plant in California might prove challenging, 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 Four Corners region or for sale in Texas.

Later in this report, in Section 5, "Coal-Based IGCC + CO_2 Sequestration Financial Analysis," the financial analysis for each of the seven cases evaluated under the differing pricing scenarios is discussed in depth. That study shows that there is likely to be an adequate financial return from an IGCC+S project, quickly summarized here, Exhibit 1-1.

Exhibit 1-1
The IGCC+S Projects Described Here Are Expected to Have Adequate Rates of Return on Equity



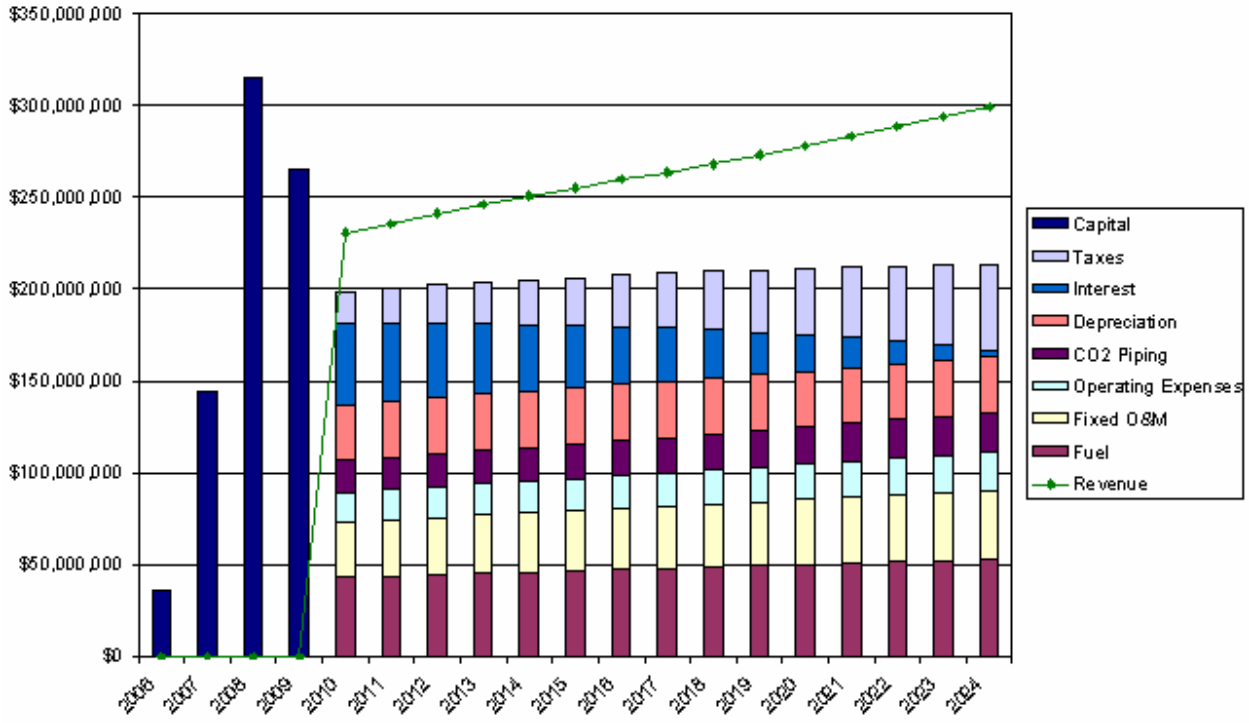
California is in desperate need of new baseload generation, so a coal-fueled plant such as this would likely prove solidly profitable to an owner. Such a unit would need to be equipped with expensive environmental control equipment to provide exceptionally low environmental emissions. In addition, supplying 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. The CO_2 has economic value in the regions chosen, since it can be sold to oil well owners for injection into the earth to enhance the amount of oil recovered from oil wells. The San Joaquin Valley and Four Corners locations are thus both convenient sites for sequestration of the plant CO_2 and for providing an added revenue stream from sales to oil well owners. The added revenue helps pay for the added equipment needed to remove the CO_2 from the plant.

The total financial return from baseload electric sales in the state and from the sale of CO_2 is good enough to make such a project happen, standing on its own feet without subsidy or need of carbon tax.

Based on the assumptions contained within this evaluation, a coal-based IGCC+S power plant would generate an Internal Rate of Return (IRR) to its owners over 17% during the 15-year period of the outstanding debt, Exhibit 1-1. The project is estimated to provide over $700 million in cash to the equity investors, three times what they invested, Exhibit 1-2. These examples are just some of the financial evaluations found later in the report.

Exhibit 1-2 IGCC+S Avoided Cost Pricing

(IGCC+S Plant located in the San Joaquin Valley)



The preliminary evaluation here shows such a project to be economically attractive. Thus, a more thorough evaluation of such an IGCC+S project is highly recommended. California has become, and will remain very dependent on one fuel: natural gas. A coal-fueled plant like this

IGCC+S would thus insulate its owners from natural gas price volatility or shortages that most all other competing natural-gas-fueled plant owners in California would be subject to during periods when the when peak electric and gas demands coincide in the state. That means such an IGCC+S unit could compete more profitably during those periods. This type of IGCC+S plant would add much-needed fuel diversity to the lopsided California electric generation portfolio. An ultra-clean IGCC+S plant like this would prove a very attractive example to the people of California of what modern clean coal equipment and technology could do to provide economical generation to sustain the energy and environmental needs of their state.

Summary of the Study Approach. You will find a thorough discussion of the study procedures, assumptions and results in the Sections 2 through 5 that follow. The brief summary given here should help guide the reader through some of the principal issues presented in these later detailed descriptions.

The California competitive market was established in 1998. Since then the California market has experienced numerous problems, so much so that the Federal Energy Regulatory Administration categorizes it as "dysfunctional." This has resulted in capacity uncertainty and volatile energy prices that have run the gamut from almost $4,000 per MWh to zero. For any supplier to invest in California, substantial changes must occur soon. The GEMSET Team presents a load forecast in this report, along with a stacking of the existing generation fleet and future fleets based on the demand for energy and the current and future changes that are likely to occur. All of these factors are weighed against risks that can be expected.

In addition to the forecast load and fleet characteristics, the GEMSET Team estimated electric prices for California based on several methodologies:

(1) Since the California market has evolved into a balancing market at the present time, capacity and energy are bought primarily on a bilateral basis by the State of California and then resold to the load-serving entities (LSEs). These bilateral arrangements are generally based on the capital and operating cost of a new combined cycle natural-gas-fueled generating unit. Therefore, one set of future prices is established based on the expected costs of such a unit providing power to California.

(2) Since the Pennsylvania, New Jersey, Maryland ISO (PJM) is considered the best example of a properly functioning competitive market, a pricing methodology utilizing the PJM day-ahead and capacity markets as a model was developed as an alternate pricing scheme to demonstrate the expected prices in California if that type of competitive market is instituted.

These two methods for price forecast allow a sensitivity assessment of expected financial return from the IGCC+S.

With the implementation of the PJM Open Access Transmission Tariff on April 1, 1997, PJM began operating the nation's first regional bid-based energy market. PJM enables participants to buy and sell energy, schedule bilateral electric sale transactions, and reserve transmission service. PJM provides the accounting and billing services for these transactions. PJM's operations are a model for many other regions contemplating —or recently converted to— bid-

based electric market operations, and is the primary reason it was selected as an example to price California's electric energy.

In order to project California electric prices into the timeframe of this analysis (2010-2024), two separate and distinct methods were employed because of the current uncertainty surrounding electric prices in California. The first is based on the marginal price of adding new natural gas combined cycles to the fleet. The State of California is currently contesting a number of contracts signed in the period after its price spike period in 2000-2001. In that appeal to the FERC, the State of California is claiming that this "avoided costs" represents an adequate return to suppliers. Carrying this forward to the time horizon of the analysis allows a reasonable comparison of the IGCC+S to the new combined cycles during that time. The second method relies on projecting market prices during that time based on a competitive market structured along the lines of that currently employed in the PJM market area. This scenario would predict that the FERC plans for Standard Market Design (SMD) would be implemented modeled after the PJM model, and this SMD would be used in California. In this method, the GEMSET Team presumes that price signals are based on the prices' relationships to production costs and demand to market prices that occurred in PJM over the past several years. This obviously assumes that California institutes a competitive market sometime in the next several years. With FERC pushing its SMD, taking most from PJM experiences, it is highly likely that California will, in fact, go back to a market-driven electric industry.

A load forecast for California has been developed based on existing and projected data from the CAISO, the California Energy Commission, and EIA, and is shown in Exhibit 1-3. The latest forecast developed in California by the California Energy Commission was in 2000. They indicated that with the problems faced by California consumers over the last few years, the need for another forecast should wait until events have settled down. Based on their information, a new forecast would be developed sometime in 2003. The EIA forecast was likewise overstated due to the circumstances described earlier, and the GEMSET Team made modifications to both based on the hourly data collected through July 2002, and then projected through 2020. The GEMSET Team views this as a reasonable benchmark for use in this report. Exhibit 1-4 is a snapshot of the expected load duration curves through the time period under investigation. It was developed by the GEMSET Team using the current load shape from the actual hourly data collected from the CAISO using the projections of peak demand and energy mentioned previously. Peak demand is expected to grow to almost 80,000 MW by 2020, while minimum demands increase at a much lower rate than peaks.

Exhibit 1-3
Load Forecast for California (2002-2020)

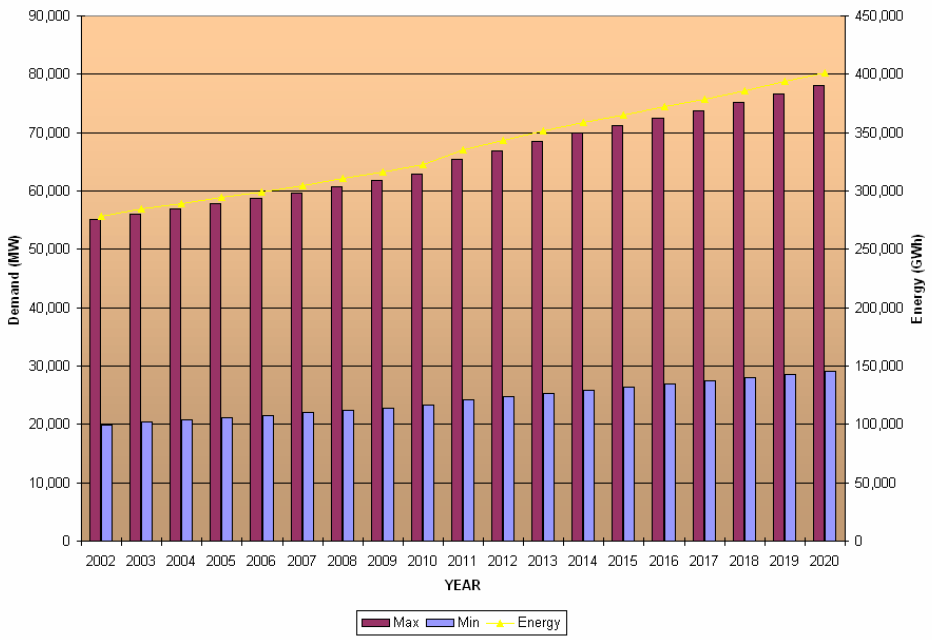
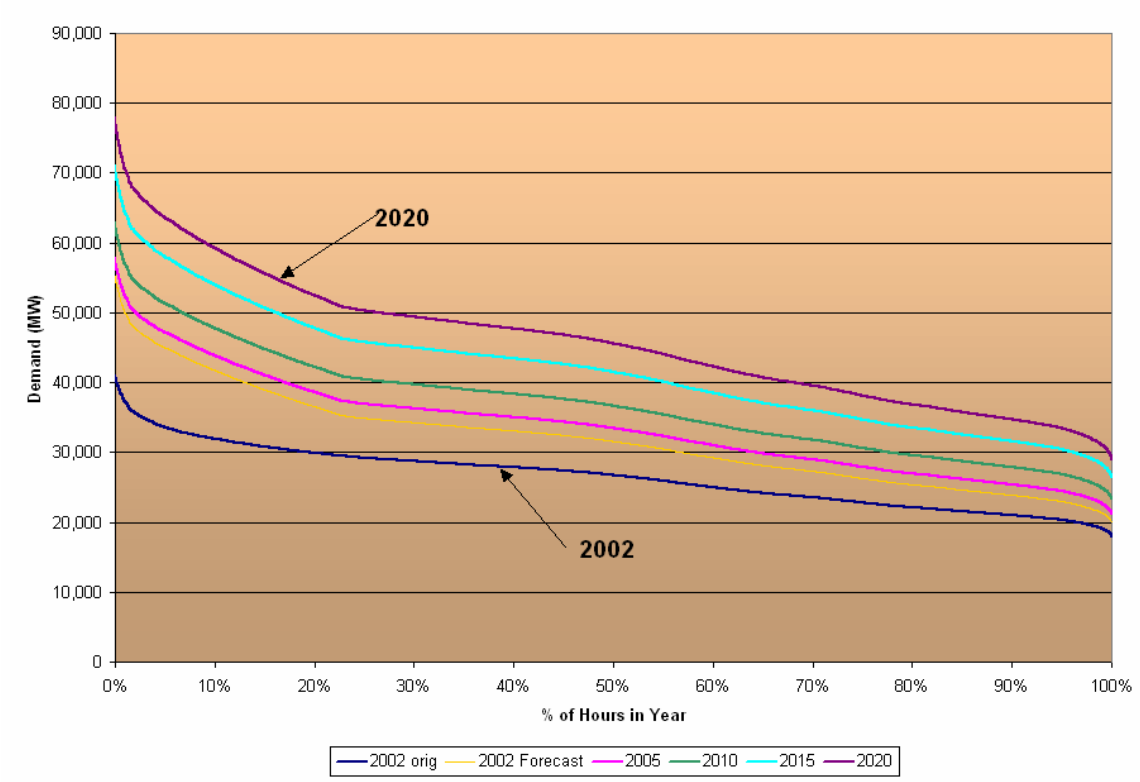


Exhibit 1-4
GEMSET Load Duration Curves Expected in California

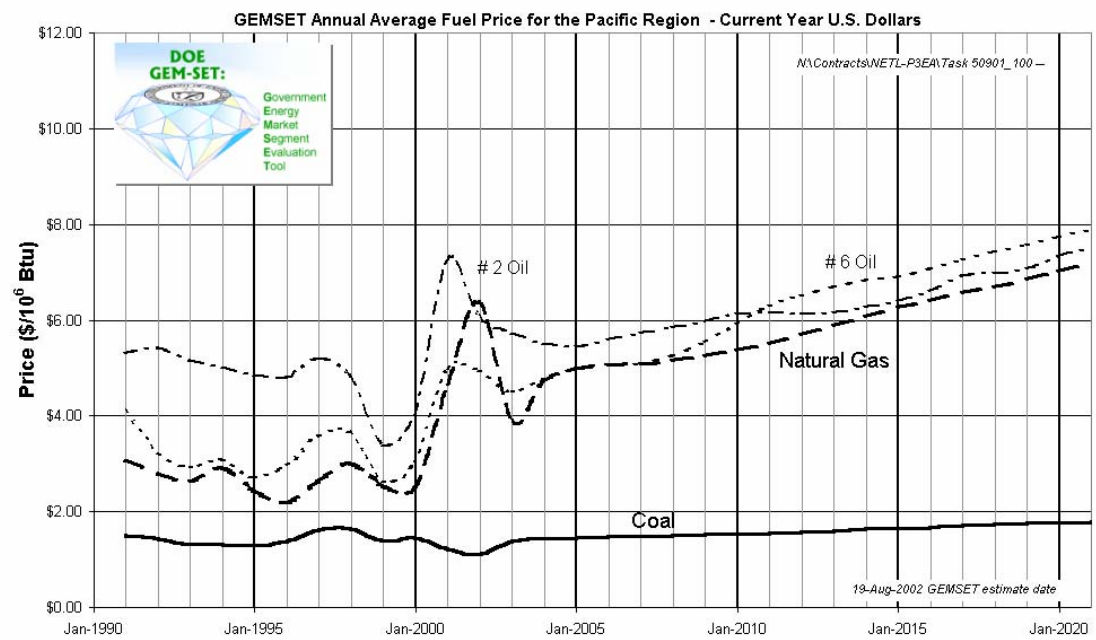


Note: The original 2002 data is for CAISO only, while all other curves are for the State of California

Coal Price vs. Natural Gas Price. In addition to the load forecast and projected makeup of the generating fleet serving California, the GEMSET Team utilizes its forecast of fuel prices through 2020 as described in its publication entitled, "2002 Fuel Price Characterization."[1] In Exhibit 1-5, the fuel prices projected by the GEMSET Team for natural gas and coal are compared for California. As shown, natural gas prices are increasing at a rate much higher than coal through the study time horizon. The prices shown here are utilized in the development of the production costs associated with the existing and projected fleet of generating units in the San Joaquin Valley of California; a different set is used for the unit at the Four Corners region of New Mexico; see Section 3, "Fuel Price and Financial Data Projections."

The fuel prices affecting every unit in the California fleet in year 2010 were evaluated, so the production costs of every unit in the existing fleet could also be projected. These serve as the basis of developing production costs that dictate the stacking order of the fleet at any given time.

Exhibit 1-5
GEMSET Fuel Price Projections – Pacific Region



Stacking the IGCC+S versus the Rest of the Fleet. The GEMSET Team established the expected capacity factors of the various units in the California fleet over the study time horizon. This is done by stacking each unit in the fleet on the basis of its production costs at the appropriate time period under evaluation. The fleet is stacked on the basis of lowest production cost to highest. Exhibit 1-6 illustrates how a fleet of units is stacked. The production cost order is an excellent approximation of the dispatch order of every single unit on the grid needed to meet expected demands on the system at any given time period. It is important to understand that this stacking (or dispatch) order changes with time when evaluating expected prices in a competitive market. The order will change over time as units are added and retired, as fuel price, or as other operating factors change.

The GEMSET Team made a separate stack of all units in each of the three study timeframes. Exhibit 1-7 shows the expected demand versus production cost profiles of the California fleet for the three time periods of 2002, 2010, and 2020.

Exhibit 1-6 Sketch Showing How Fleet Stacking Occurs for Establishing GEMSET Estimates of Production Cost Order

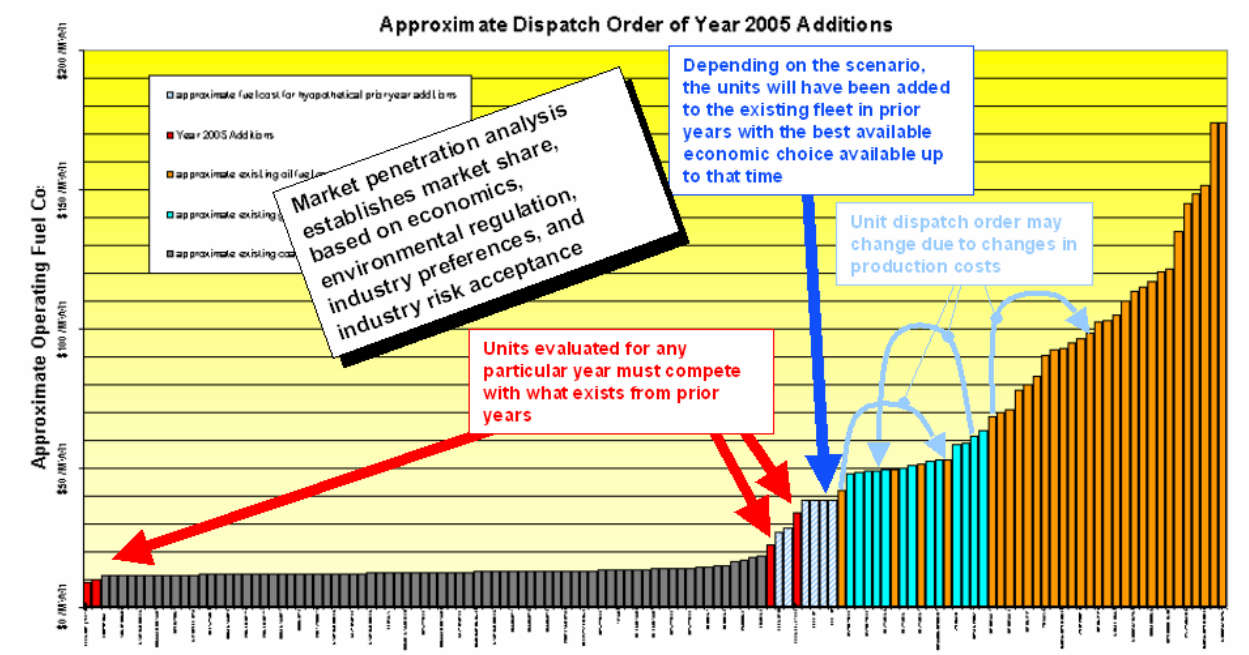
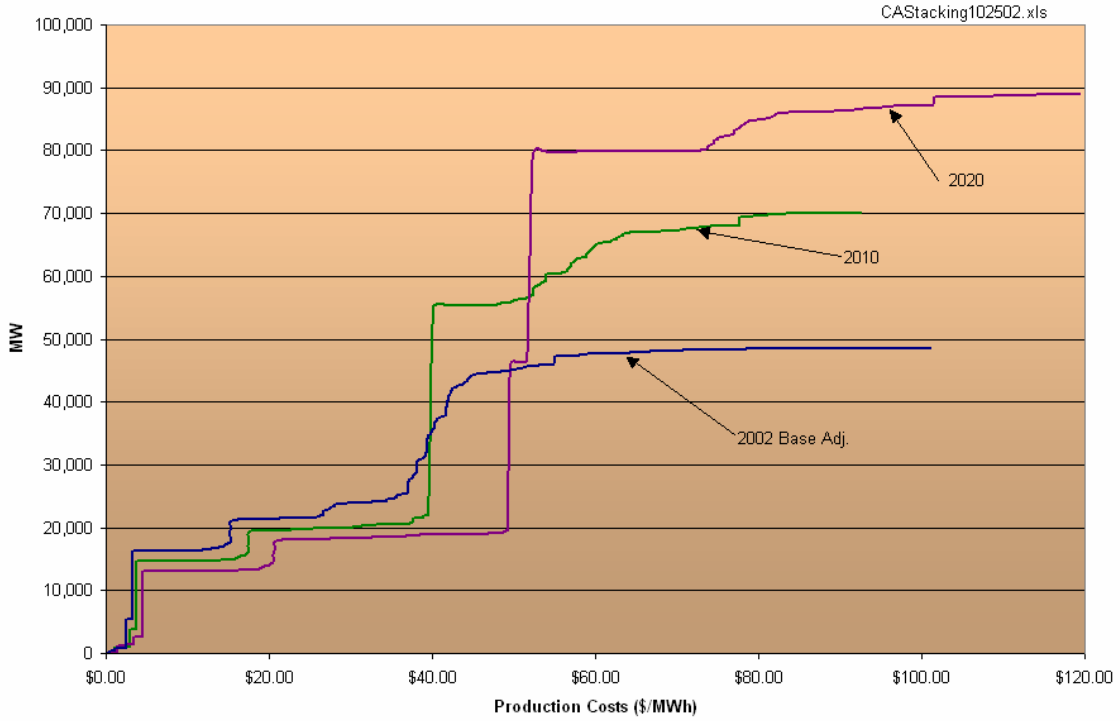


Exhibit 1-7
GEMSET Estimate of California Installed Generation Stacked by Production Cost



These GEMSET stacking methods approximate how generating company owners choose to bid their units into a competitive market. The individual stacking of each unit serves as the basis for determining the expected capacity factor[§] over time of the IGCC+S unit in this analysis.

Since natural gas price is expected to increase versus coal over time, this forces the owner of a potential new gas-fueled unit to evaluate the consequences of his higher production costs. With higher costs, the owner would be successful in bidding profitably for fewer hours during the year, so his unit's capacity factor would be lower because of the higher production costs forced by his increased gas price. A unit like the IGCC+S, with lower coal-based production costs, would therefore have a higher capacity factor and, potentially, higher revenues as time goes on. Adding a coal-fueled unit like an IGCC+S would displace competing NGCC capacity and force the competing NGCC to lower capacity factor.

What is Found in this Report. The summaries above give just a brief tour of how the study was performed, and quick assessment of results. The sections that follow in this report fully document the historical, technical, and economic and financial data that form the assessment of an IGCC+S plant considered for electric generation supplying the California power market. The GEMSET Team also assessed as an alternative, an IGCC+S plant that could be located outside of California but have its electricity sold in the California market. The sections of this report that detail the full scope of the investigation include the following discussions:

- Section 2, "California Regional Data," describes the wholesale energy price structure of the California market, its current and projected structure. It will also present the expected load requirements in California through 2020, and the structure of the fleet. These data will serve as the basis for evaluating the IGCC+S power plant within this expected structure. The histograms that characterize the actual year 2002 price duration persistence and load duration persistence in the region are used as the basis for many of the economic projection evaluations in this report that focus on price. This is the region's historical demand and price data, with information about energy prices, generation mix, and baseload demand.

- The economics of generation cannot be established without first establishing the current and projected fuel price for the generating units in the region, and the projected production costs of the fleet and estimated electric price that a power facility might expect over a period of time. Section 3, "Fuel Price and Financial Data Projections," discusses the basis for the fuel and electric prices used in this analysis.

- Section 4, "Market Study Assumptions for CO_2 Sales and IGCC Use ," presents the market data for CO_2 in California and other regions, and then discusses the technical and cost information associated with an IGCC+S type power generating unit.

- The main report body discussions conclude with Section 5, "Coal-Based IGCC + CO_2 Sequestration Financial Analysis," which presents the financial analysis conducted for

[§] Cf = [actual kWh] / [period hours * rating]

each of the seven cases evaluated under the differing pricing scenarios, and the results of that investigation.

- The references used to prepare the various sections of this report are listed in Section 6 at the end of the main body of the report.

- Finally, an Appendix is included at the back of the report to give the detailed financial statements expected for each of the seven study cases evaluated. These are the following:
  - Case A. IGCC+S San Joaquin Valley Avoided Cost Pricing Financial Statements
  - Case B. IGCC San Joaquin Valley Avoided Cost Pricing Financial Statements
  - Case C. IGCC+S San Joaquin Valley Competitive Pricing Financial Statements
  - Case D. IGCC+S Four Corners Region Avoided Cost Pricing Financial Statements
  - Case E. IGCC Four Corners Region Avoided Cost Pricing Financial Statements
  - Case F. IGCC+S Four Corners Region Competitive Pricing Financial Statements
  - Case G. CO_2 Sequestration Standalone Financial Statements

2. California Regional Data

This section discusses the California regional data[2] and assumptions used in the DOE GEMSET market analysis model. The California Independent System Operator (CAISO) is now responsible for administrating the competitive market. CAISO is significantly different from a regulated utility market where new generation options are approved by a commission or regulatory body. Under a competitive market, new generation is at more of a risk than in a regulated market, as demonstrated by the happenings in California.

2.1 The Independent System Operator: CAISO Interconnection

The competitive electric power system had originally included the California Independent System Operator (CAISO) and the California Power Exchange (CalPX). Now, however, CalPX has been eliminated. The competitive electricity market has been operating in California since March 31, 1998. During that first year, 231,400 GWh of electric power were traded in the CalPX Day-Ahead Market and the CAISO Ancillary Services and Real-Time markets, involving $12 billion of transactions on the buy and sell sides. This established a market totaling $6 billion in dollar volume. The number of generating company participants in the Day-Ahead Market increased from 39 at the start to 68 participants by July of 1999. The market system was then working. Then came problems which culminated in electricity shortages and price spikes in California. Now, in response to those problems, the California electric power market is in a state of transition. The State of California in a very short time period has made several wrenching changes: from fully regulated markets, to unregulated competition, to a point where few know exactly what will happen in the future. Until the State of California settles on a stable market structure, the state's generation suppliers and customers both have faced, and will continue to face, many challenges.

2.2 Territory

With the bankruptcy of the CalPX, the California ISO is now responsible for the day-to-day operation of one of the largest centrally dispatched electric systems in North America. As shown in Exhibit 2-1, the CAISO is responsible for the administration of the bulk of electricity sales in the state. Over 85% of California's electric needs are handled by the ISO, which is charged with ensuring that safe and adequate resources are available.

The State of California regulatory commission and the Federal Energy Regulatory Commission (FERC) have jurisdiction within the CAISO control area. The FERC, as part of its approval of California's electric industry restructuring, ordered both the CAISO and the CalPX, when it was

operating, to maintain ongoing surveillance of their respective markets. The FERC also ordered the monitoring functions of each institution to cooperate, recognizing the integrated character of the CAISO and the CalPX markets. Since the shutdown of the CalPX, the CAISO has taken over much of the responsibilities previously handled by the CalPX. The California Public Utility Commission and the California Energy Commission are also major players in the structuring of the California electricity market.

Exhibit 2-1
Territory of the California ISO

Source:
www.caiso.com, information kit

2.3 CAISO Responsibilities

California's restructured electricity industry is complex, with traditional utilities, private generating companies, and State of California agencies each playing a variety of roles and carrying different responsibilities. The CAISO, a not-for-profit public benefit corporation, is one link in this chain, but an important link. The CAISO is the impartial operator of the State of California's wholesale power grid—maintaining reliability and directing the electron traffic on the transmission superhighway that connects energy suppliers with the utilities that serve 30 million Californians.

For consumers, the CAISO makes sure the electrical needs of all customers are met around the-clock—and that reasonable wholesale costs are fostered. For energy companies, the CAISO ensures equal access to 25,526 circuit miles of transmission lines and conducts open and fair spot markets that are used as a last resort to balance the system.

The Folsom-based CAISO assumed computerized command of California's wholesale power grid on March 31, 1998, directing the flow of electricity along long-distance, high-voltage power lines that connect California with neighboring states as well as Mexico and British Columbia. The ISO manages the transmission lines and supervises maintenance, but the transmission systems are still owned and maintained by individual regulated utilities. The ISO also acts as a transmission planner, identifying and approving the enhancements that transmission owners make to the grid to meet high standards for reliability.

Most electric sales in California are bi-lateral agreements between electricity generators and the State of California. The ISO operates a small fraction (less than 10%) of the total wholesale electricity marketplace —using markets only to allocate transmission space, maintain operating reserves, and match supply with demand. Those markets are watched closely by economists with the ISO's Department of Market Analysis, who keep a constant eye on wholesale prices, policing any market power abuse. In addition, the ISO's Compliance Department ensures that market participants meet their obligations by monitoring responses to dispatch instructions and imposing penalties for non-compliance.

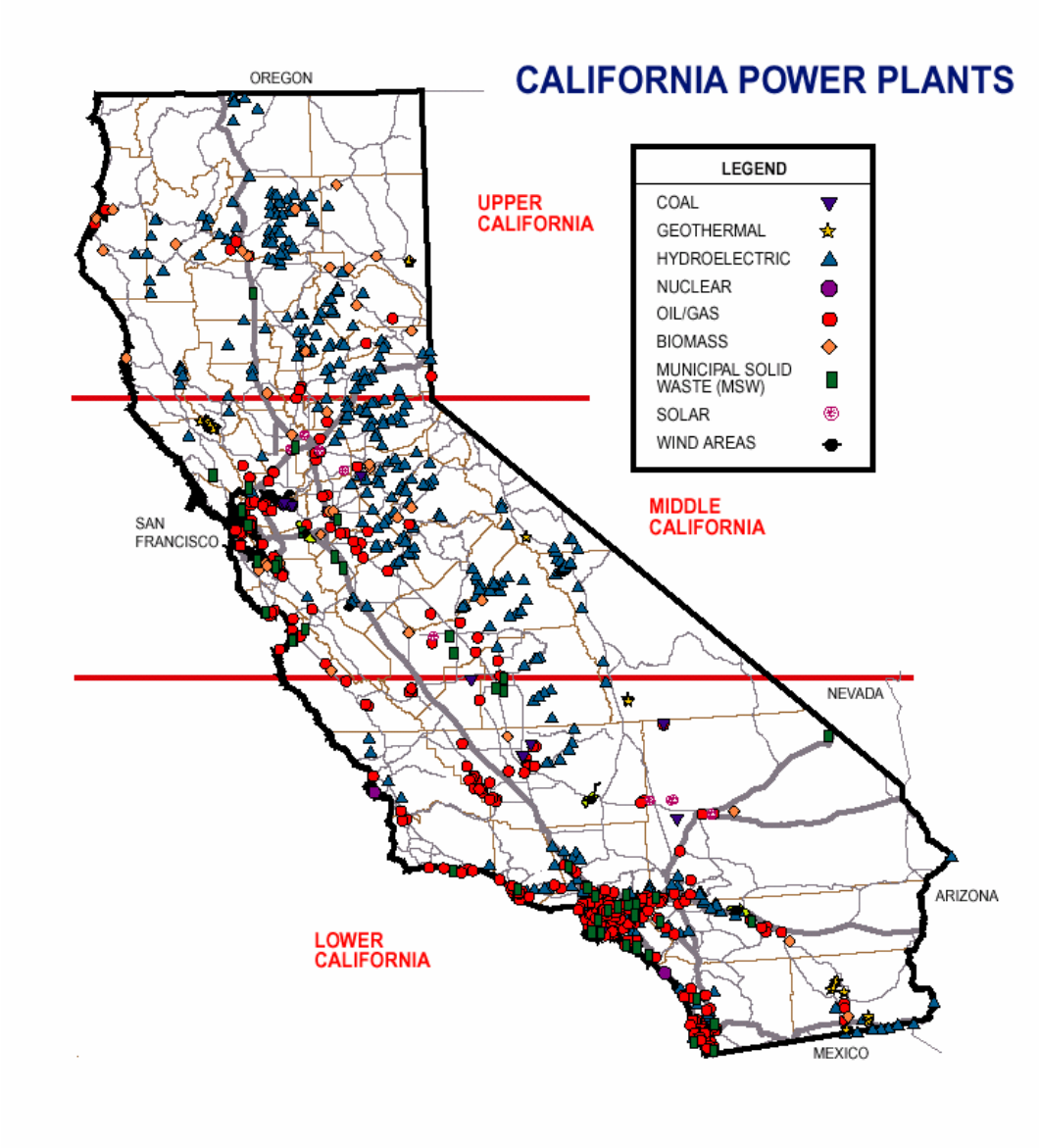
The core functions of the CAISO:

- Provide open and nondiscriminatory transmission service.
- Ensure safe and reliable operation of the grid.
- Operate energy and reliability markets in a responsive, flexible, and transparent manner.
- Foster reasonable energy costs for California consumers.

2.4 Generating Resources

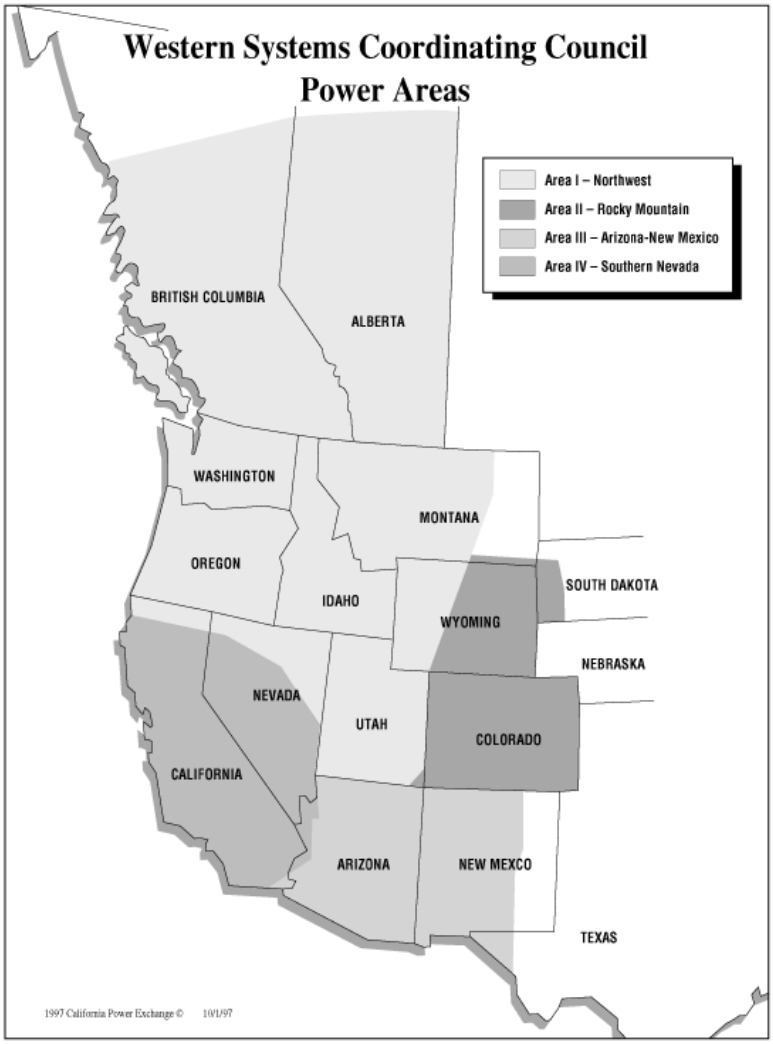
In Exhibit 2-2, the map displays the type and location of the major sources of generation in California. In Exhibit 2-3, the map shows the area of the Western Systems Coordinating Council, of which California is a member.

Exhibit 2-2
California Power Plants



Source: www.caiso.com; PPSTATE.pdf

Exhibit 2-3
WSCC Power Areas



2.4.1 California Transmission Import and Export Capabilities

In addition to its own in-state generating resources, California does maintain significant transmission capabilities with its neighboring states in order to both import and export power.

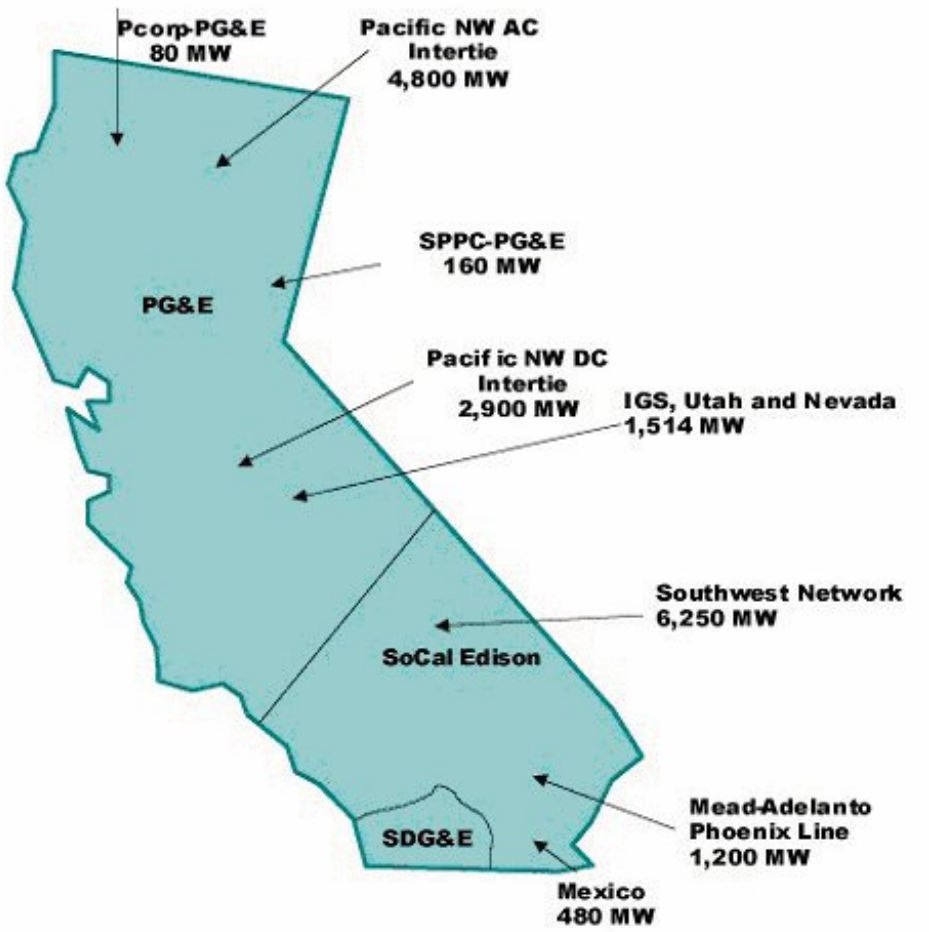
Electricity is imported to California when imported energy is lower in price than electricity generated by natural gas and during periods of drought, when hydroelectric generation is lower.

The Pacific Northwest, which is winter peaking, has a large hydroelectric generating capacity that can be exported to California during late spring and summer. California, in turn, provides power to the Northwest to meet winter heating loads.

Coal-fired plants outside of California in the Southwest also produce electicity that can be imported to California at varying times of the year.

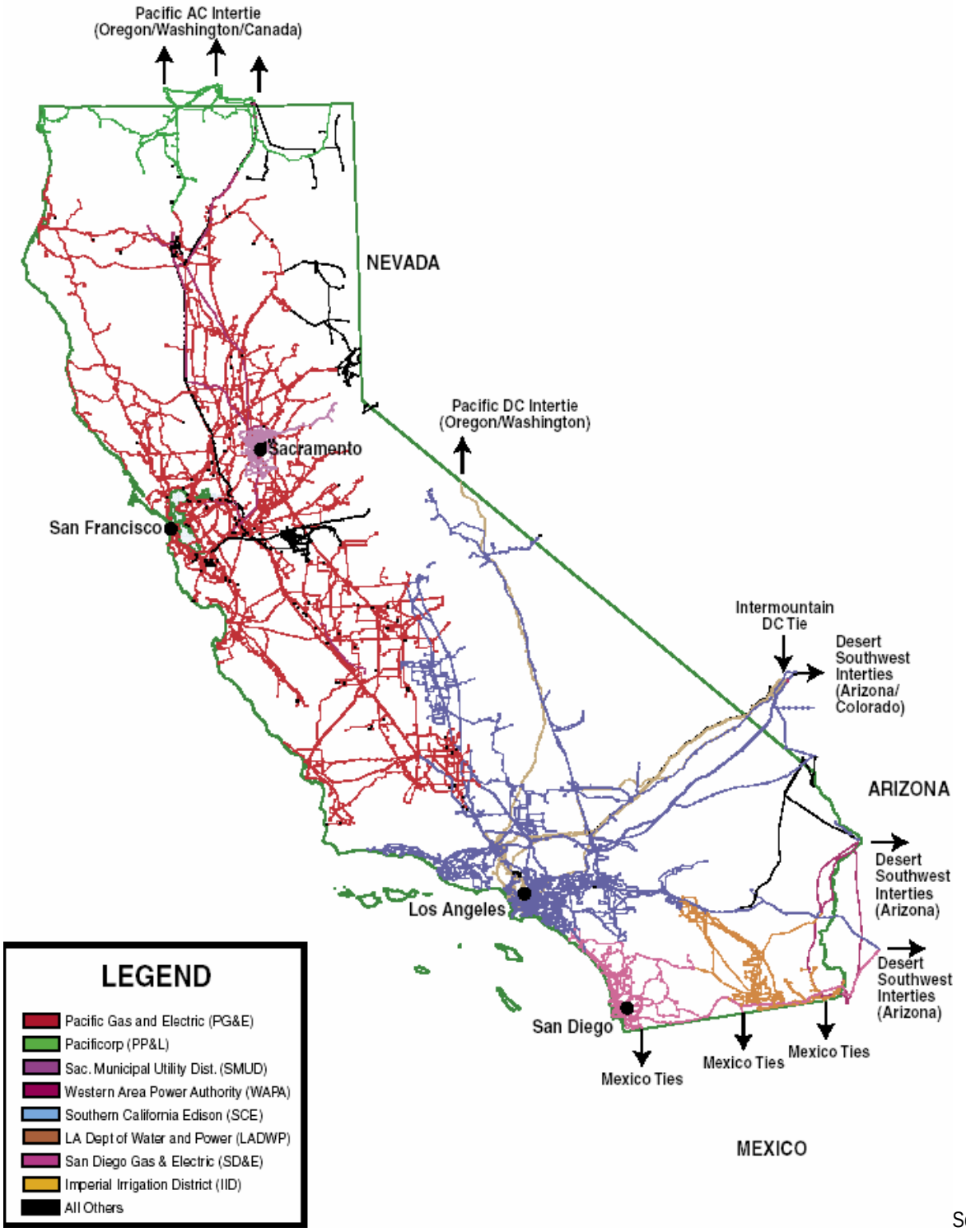
Exhibit 2-4 shows the major electric power import and export transmission capabilities in the region, while Exhibit 2-5 provides the details of the transmission network in California.

Exhibit 2-4
The Capability of California Transmission to Import and Export Electric Power



Source: California Energy Commission

Exhibit 2-5
Transmission Network in California



Source:
www.caiso.com; TRANSMISSION_LINES.pdf

2.5 Update on Energy Commission's Review of California Power Projects

In the early 1990s before the State of California's electricity industry was restructured or deregulated, the California Energy Commission certified 11 power plants. (None were larger than 240 MW. The largest plant licensed prior to the 90s was the 385 MW Arco Watson Cogeneration facility licensed in 1985.) Of the plants licensed in the 1990s, three were never built due to market conditions. Eight of those approved plants generate 952 MW of electricity. Additionally, a project approved in 1994 had a 44 MW second phase that is now on line.

Only one power plant application was filed with the Energy Commission between 1994 and 1997 because of uncertainty of market conditions and the restructuring of the electricity industry.

Since March 1998 when electricity deregulation started, the Energy Commission has approved more than 30 power plant projects, though not all plants approved will be built. Three "major" power plants, totaling 1,415 MW, came on line in 2001 and are producing electricity. Another 684 MW from "peaking" power plants were on line by early 2002. Except for two emergency peakers that came on line in early 2002, two plants totaling 978.4 MW have come on line in the rest of 2002. Also the 530 MW Unit 1 of the Moss Landing Power Plant came on line July 1, 2002, with the plant's 530 MW Unit 2 coming on line July 11th (a total of 1060 MW). Therefore, a total of 15 power plants totaling 4,137.4 MW have come on line since deregulation.

2.6 Load Forecast

In 2000, the California Energy Commission published its latest demand and energy forecast for the State of California. After the chaos experienced during late 2000 and 2001, electric demand experienced substantial drops as a result of higher prices at both the wholesale and retail level, and government asking for consumers to reduce load due to shortages in capacity (since believed to be artificially created by some suppliers). Recently the Commission indicated that a new 10-year forecast would likely be available early 2003. In addition to the Commission forecast, EIA publishes a long-term forecast for each state, and for the years 2011-2020, that projection was utilized. The combination of the two forecasts is shown in Exhibit 2-6. Each of those forecasts projected energy and demand, but no hourly information that would be applicable. Therefore, the actual hourly data collected by the GEMSET Team as part of the California characterization was used to synthesize the hourly loads throughout the study horizon. That information and the relationship between the 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 Exhibit 2-7.

Exhibit 2-6
GEMSET Long-Term California Demand and Energy Forecast

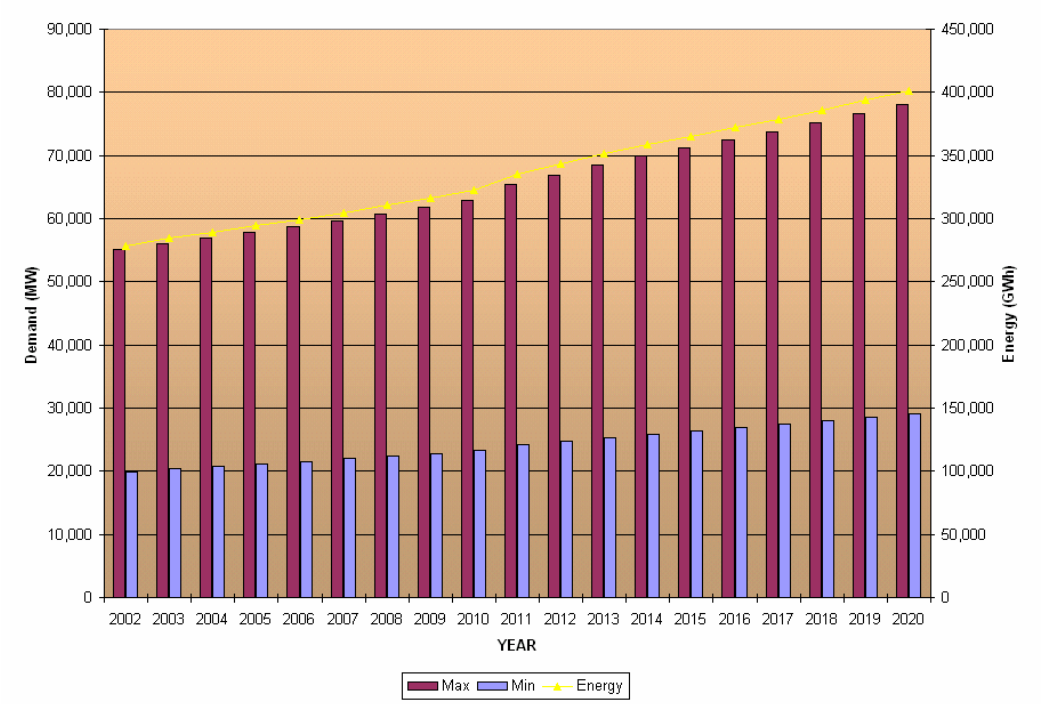
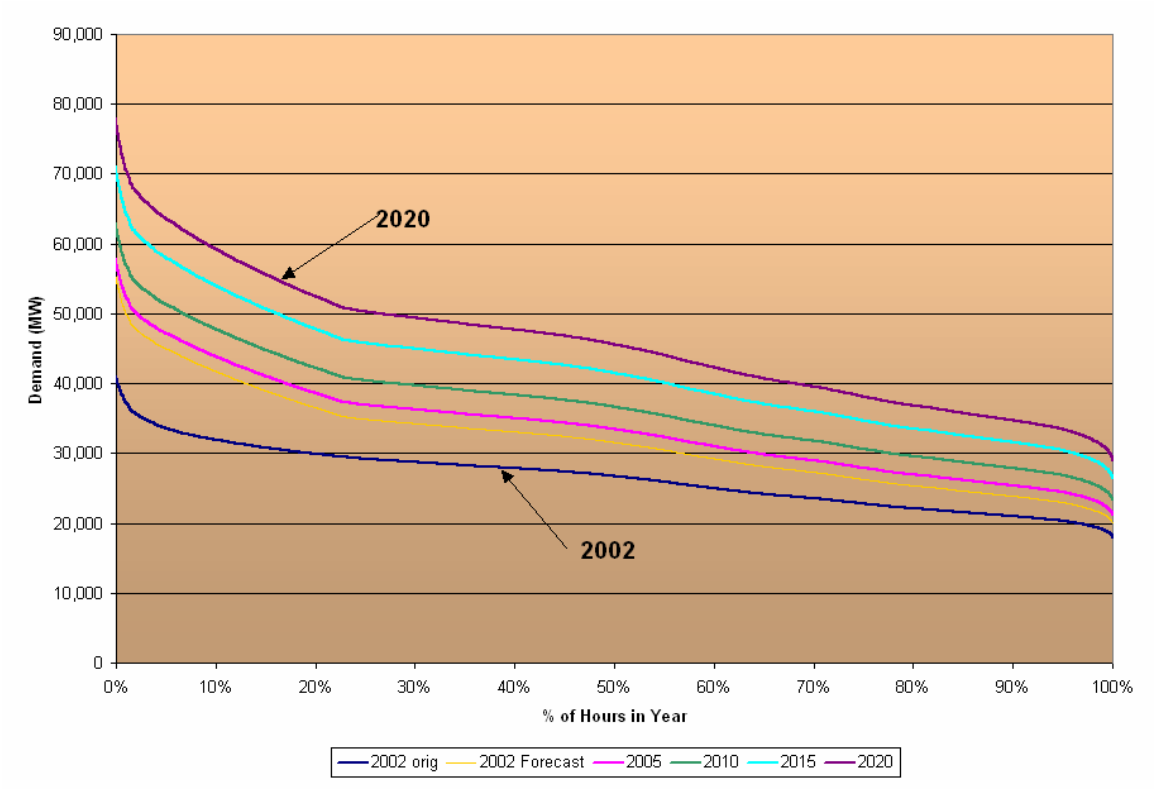


Exhibit 2-7
GEMSET Estimated Load Duration Curves for California



As clearly indicated in the graphs, the peak demand is increasing at a greater rate than the minimum demands. This is purely a function of the energy forecast versus the demand forecast. The actual capacity factors utilized in the forecast are increasing by a small percentage each year as a result of demand side management and other factors. Overall, the forecast utilized in this analysis is considered adequate for use in this investigation.

2.7 California 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 waste heat resources. In the development of pricing scenarios in the GEMSET Desktop Model, the units are then stacked by production cost (low to high) to establish dispatch order.

The GEMSET database of identifies a total of 1,423 units as serving California load from within California. . According to the records, California has over 20 different types of generating units in its fleet. The total nameplate rating of the units in the fleet is slightly more than 57,000 MW of capability.

In an attempt to structure the future fleet of generation in California, the makeup of the existing fleet is shown in Exhibit 2-8. This is the current makeup of the fleet in the GEMSET database. It should be noted that the bulk of generation in California is comprised of natural gas fueled generation and hydro. There is currently a small amount of coal-fired generation in the state.

Even though California has installed capacity much greater than its demand for electricity, this must be tempered with the realization that much of their generating units cannot be considered firm capacity. Many of the wind units and a significant portion of the hydro units are considered to be energy-only type generation. Therefore, an adjustment was made to the total installed capacity to reflect reasonable assumptions for firm capacity. Exhibit 2-9 shows the total adjusted equivalent firm capacity calculated based on the following assumptions:

- Landfill gas – 50% of nameplate rating;
- Wind and solar – 25% of nameplate;
- Hydro – 60% of nameplate; and
- Waste heat – 75% of nameplate.

This reduces the firm capacity to a level of about 48,400 MW.

Exhibit 2-8
Base Generating Fleet in California (2002)

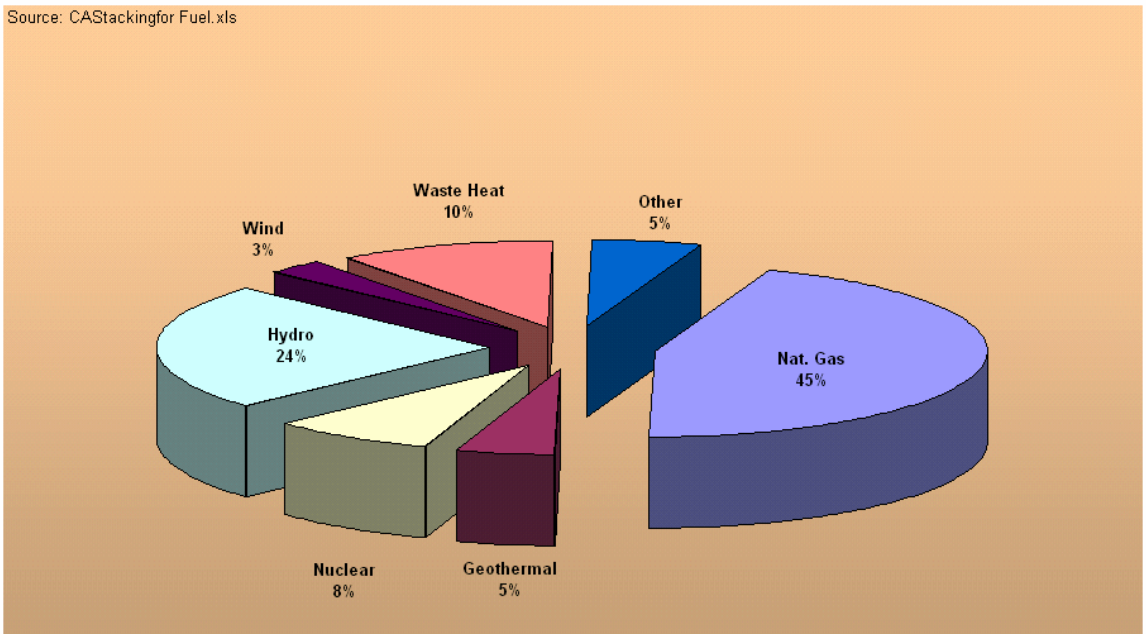
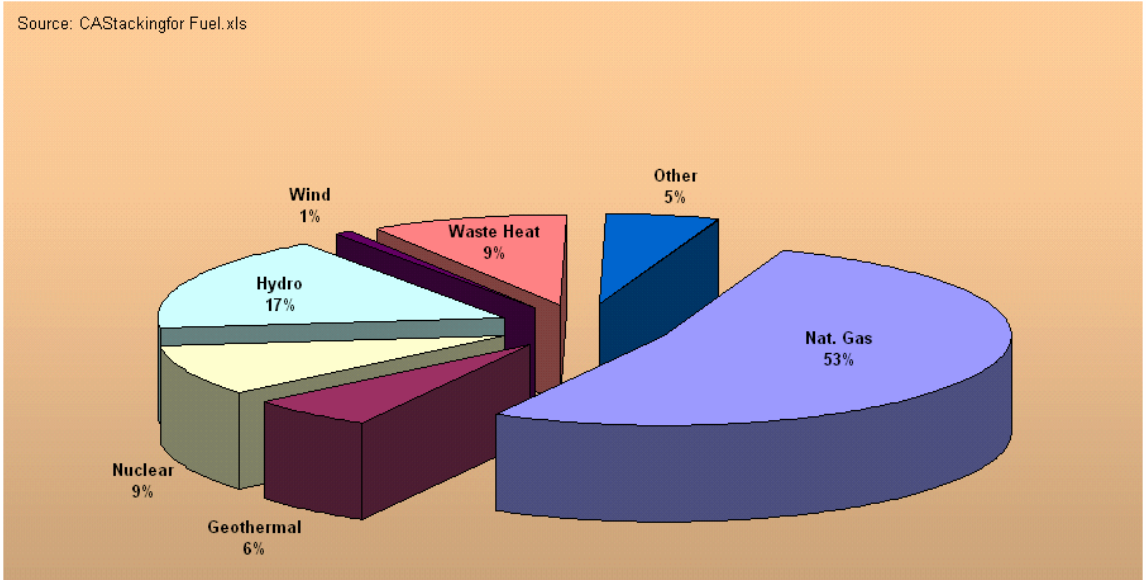
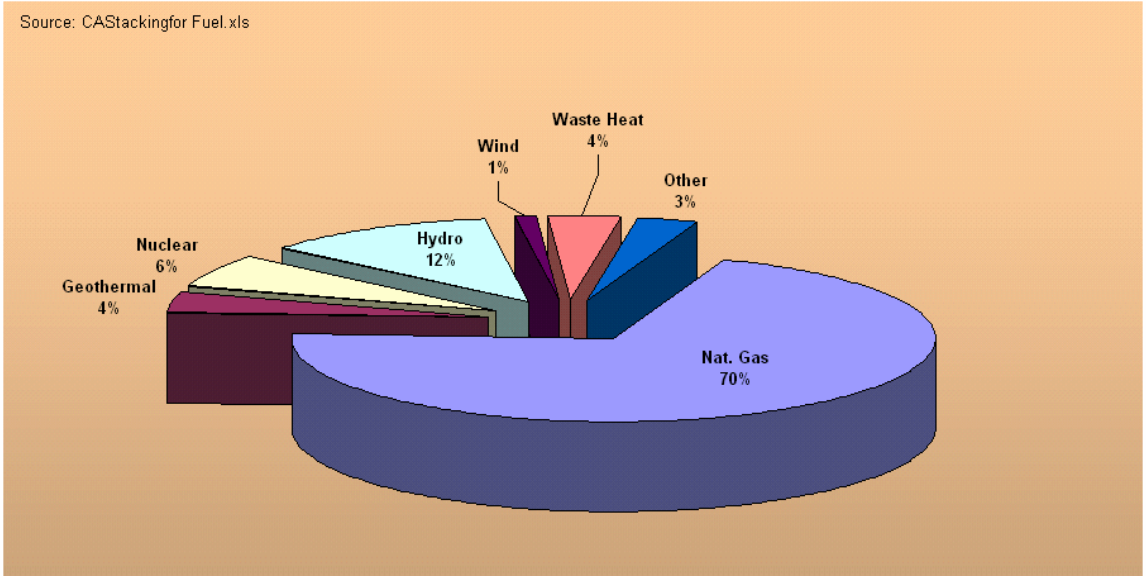


Exhibit 2-9
Adjusted Base Generating Fleet in California (2002-Adj)



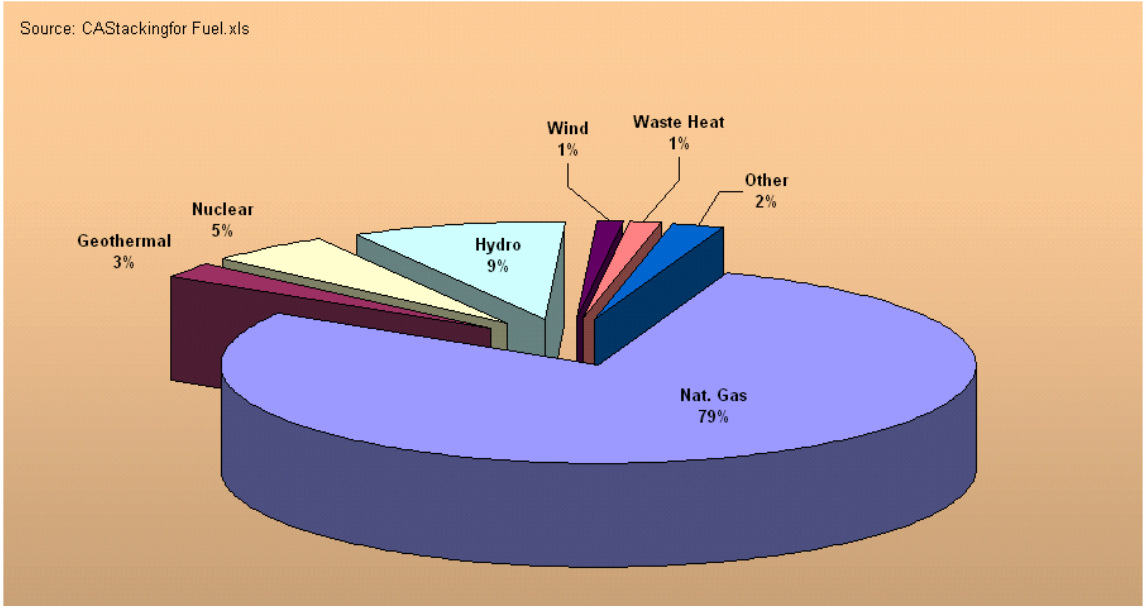
By 2010, there will be a need to add over 33,000 MW to the existing fleet to enable California to meet its capacity obligations. Approximately 12,200 MW of existing generation was assumed retired during the time frame between 2002 and 2010, consisting primarily of natural gas (9,241 MW) and waste heat (2,495 MW). These retirements were based on the age of the existing units reaching 45 years of age, and consists of old natural gas steam turbines and old gas turbines. Over 95% of the units assumed retired were old natural-gas-fueled steam turbines. 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 Exhibit 2-10. 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.

Exhibit 2-10
Projected California Generating Fleet (2010-Adj)



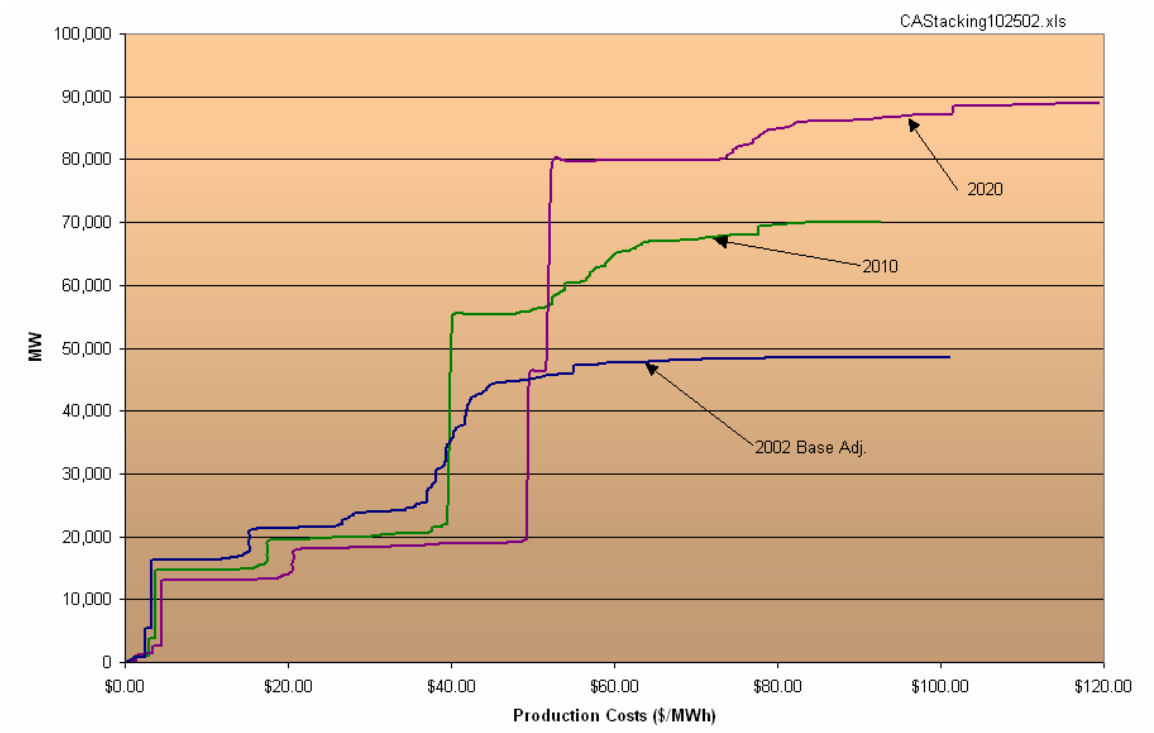
By 2020, there is a need to retire an addition amount of generation totaling almost 8,000 MW of fossil fueled generation due to its age. By that time, the fact that California has not built much generation in the 80s and 90s results in their fleet being extremely old, requiring replacement of capacity. For this analysis, it is projected that California will have to install over 55,000 MW of new generation capacity through the period of 2002-2020. By the end of this time frame, California will be relying on almost 80% of its generation on natural gas, given the current emphasis on nothing but natural gas as its fuel of choice. This exposes California consumers to massive price spikes if the price of natural gas reaches the levels it did in the winter of 2000. Exhibit 2-11 shows the breakdown of the projected fleet in 2020, which is estimated to provide approximately 89,000 MW of capability.

Exhibit 2-11
Projected California Generating Fleet (2020-Adj)



The three distinct estimates of generating capacity in California are then stacked according to their production costs from low to high. This represents the estimated stacking order for dispatch purposes in the analysis. It will indicate where the IGCC+S will be in the stack and how many hours it can reasonably be expected to run in the California market. In Exhibit 2-12, the production costs of the three fleet stackings are shown for the three years under investigation.

Exhibit 2-12
GEMSET Estimates of Production Costs Versus Demand



Due to the continued emphasis on natural gas generation, the fleet production costs at around 20,000 MW of demand goes straight up for the amount of natural gas generation in the stacking order. As mentioned previously, this puts the consumers in California at risk in the event that natural gas prices reach the levels they experienced in the winter of 2000 and 2001.

2.8 Fleet Dispatch Stacking Order Assumed

For any given scenario, all of the units in California are assumed to compete successfully in their stacking order on the basis of their threshold bid prices. That is, the unit with the lowest threshold bid price in the fleet will capture the first increment in demand and thus have the highest capacity factor. The next unit in threshold bid price-stacking order will take the next increment in demand, etc. In periods of low demand, only the lowest price units would be used; in periods of peak demand, most all units would be used.

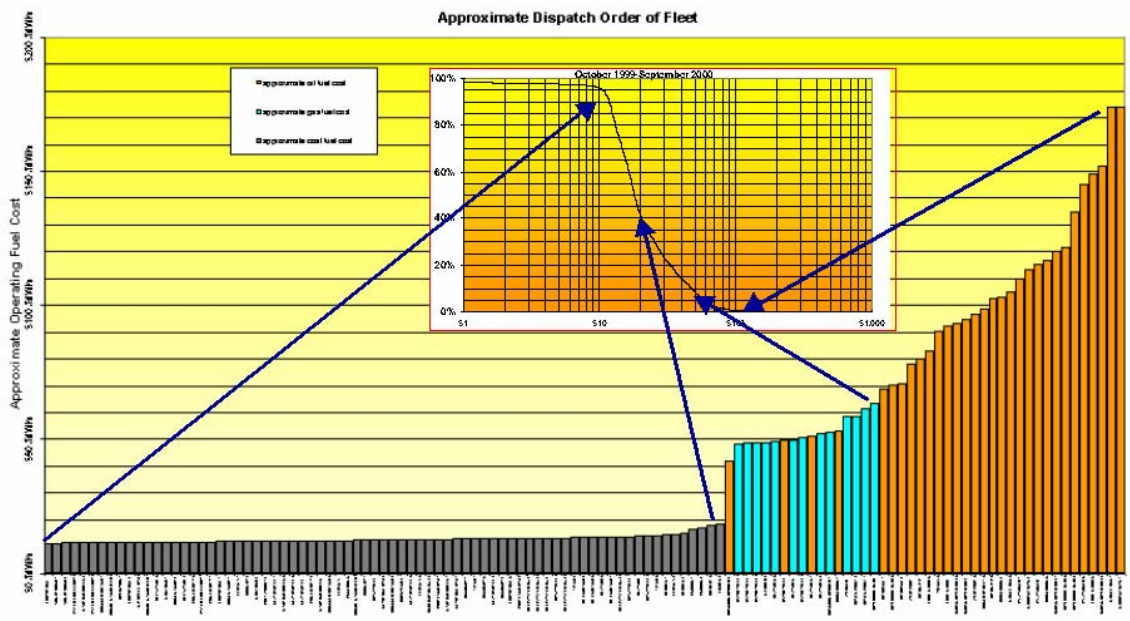
This stacking order changes depending on the scenario. For example, if the natural gas price were lower in one scenario versus another, then the natural gas units would be dispatched earlier in the stacking order.

2.9 Relating Threshold Bid Price to Demand

Threshold bid price forms the basis for stacking the competitive order of dispatch for all units. Since the current price structure in California masks market price, the threshold ratios from the PJM system are used instead.

Stacking the Existing Fleet. Exhibit 2-13 is a sketch (not real data) that shows the price histogram as the small inset curve, and gives a visual indication of how the units in the fleet meet that price demand.

Exhibit 2-13
Sketch Illustrating the Stacking of the Existing Fleet to Establish Threshold Bid Price vs. Demand Relationship



This sketch gives a visual impression of the process; however, the actual mapping of the units in the fleet to price is a more sophisticated operation than this visualization suggests. In the GEMSET model, it is assumed that perfect competition occurs, so that the lowest price producer is assumed clever enough to always underbid the next higher threshold bid price producer. While this assumption is a simplification, on average, it is a reasonable enough presumption to characterize the threshold bid price characteristics of the region. With the large number of generating units within the region, this provides a good approximation of the order in which units will make up the generation.

Under this presumption, at low demand periods, when the price is low, only the lowest threshold bid price units can afford to operate. As demand increases, the next higher threshold bid price unit is added, then the next, until at the periods of peak demand, finally, the high threshold bid price peaking units gain a high enough return to be called into service.

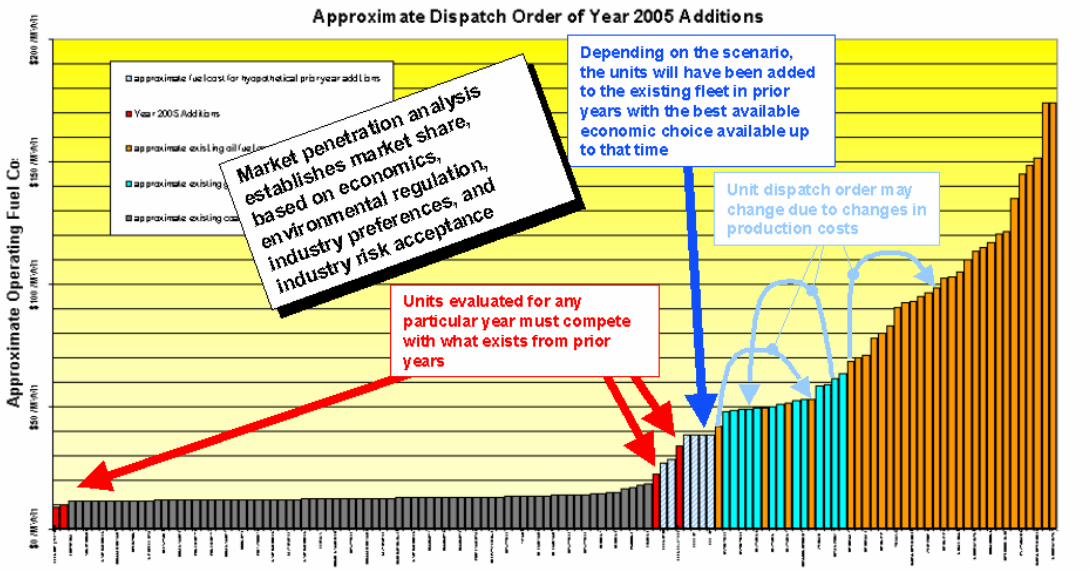
In the GEMSET model, the stacking is used to establish the generating cost characteristics of the fleet for each level of demand. This stacking is discussed in detail later on in Section 4, "Market Study Assumptions for CO_2 Sales and IGCC Use Serving the Electric Needs of California." The baseline threshold bid price versus cumulative megawatt capability of all of the PJM units used as the competitive base is described later in Section 3.6.1.

2.10 Forecasting a Scenario's Day-Ahead Electric Price Profile

2.10.1 Re-Stacking the Dispatch Order

The first action needed to build the expectation of a scenario's day-ahead electric price profile is to re-stack the units considered. These must be re-stacked in the revised threshold bid price order. The threshold bid prices of units will change since fuel price or demand profile, or other factors might change in any scenario, compared to the circumstance that existed in the historical data baseline. In any given scenario individual units will likely have a different production order than in the baseline. For example, were gas price to change, several natural gas units have been "promoted" in their dispatch order to earlier dispatch, while oil units were "demoted" since their scenario threshold bid price places the lower-priced units ahead of what have now become more costly units. Exhibit 2-14 is a sketch to give a visual impression to illustrate the concept. The actual GEMSET re-stacking process is more sophisticated.

Exhibit 2-14
Re-stacking the Fleet to Establish Threshold Bid Prices vs. Demand Relationship for a Scenario



2.10.2 Re-Stacked Scenario Threshold Bid Price Histogram

Once the units are re-stacked, a scenario's threshold bid prices versus cumulative megawatt capability of all of the scenario units are plotted. This is done later in Section 3.

Demand Growth Extrapolation. Since demand in a scenario may exceed the available capacity, it is important to make judgments on the likely price for imported replacement energy. In GEMSET a linear extrapolation is used for the estimated threshold bid price for all capacity beyond that of the fleet. The extrapolated scenario threshold bid price versus cumulative megawatt "tail" is added to the re-stacked histogram, to form the final threshold bid price versus demand curve, should demand in an evaluation scenario exceed in-state generation capability. This emulates energy import prices during constrained periods.

Scenario Day-Ahead Price Estimate. Once this scenario threshold bid price versus demand curve is known, the scenario's hour-by-hour demand is used to read this curve and establish the scenarios hour-by-hour expected threshold bid price. These are then mapped hour-by-hour against the "inferred competition ratio" for each hour that was established from the baseline. Thus, hour-by-hour day-ahead system price can be inferred. This mapping occurs hour by hour for each of 8,760 hours in the year. The scenario's electricity price is thus established. The day-ahead electric price is a function of the scenario's demand and the threshold bid prices for the units in the system under the scenario's production price constraints.

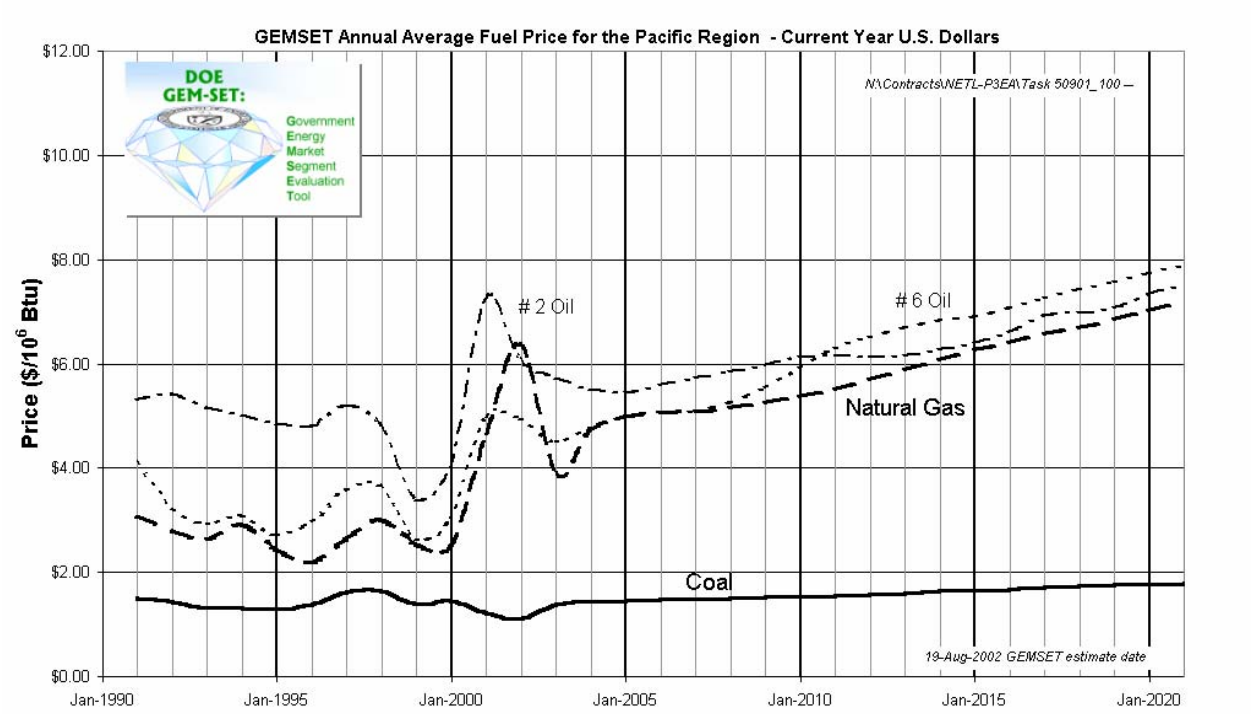
3. Fuel Price and Financial Data Projections

Delivered fuel price projections from the GEMSET 2002 Fuel Price Characterization 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.

3.1 Fuel Price in the Pacific Region

GEMSET 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 Exhibit 3-1. Projected delivered coal prices are about 60% higher in the Pacific region relative to the Mountain region, and the projected natural gas prices are about 15% higher in the Pacific region in 2010. A modest increase in the price of these fuels is projected through 2020, with the coal price increasing from $1.56 per million Btu in 2010 to $1.80 per million Btu in 2020, and natural gas price increasing from $5.52 per million Btu in 2010 to $7.21 per million Btu in 2020. These prices are higher than those projected from the National Energy Modeling System (NEMS).

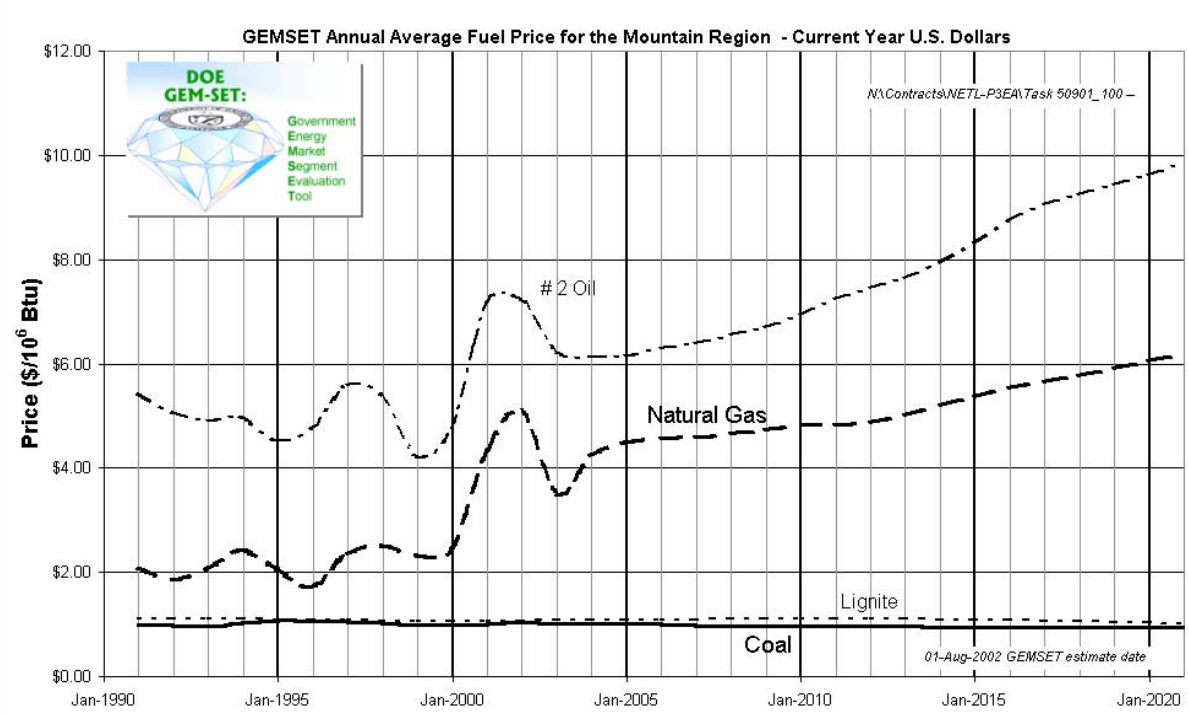
Exhibit 3-1
Natural Gas, No. 2 and No. 6 Oils, and Coal Annual Average Fuel Prices - Pacific Region



3.2 Fuel Price in the Mountain Region

GEMSET baseline annual average historical and projected delivered natural gas, No. 2 oil, coal, and lignite fuel prices for the Mountain Region, in current-year dollars, are shown in Exhibit 3-2. Projected delivered coal price in the region is relatively constant over the eleven year period from 2010 through 2020, ranging from $0.95 to $0.97 per million Btu.

Exhibit 3-2
Natural Gas, No. 2 Oil, Coal, and Lignite Annual Average Fuel Prices – Mountain Region



3.3 Other Fuels

There are other units in the California service area that use different fuels. These fuels generally contribute only a very small fraction of generation, so their depiction need not be, and are not, as detailed in the GEMSET assessments. Projections for some of these fuels are estimated based on those fuels for which GEMSET does provide scenarios. These are shown in Exhibit 3-3. Other fuels are held constant in all the regions and when threshold bid prices are developed, as shown in Exhibit 3-4. The prices are adjusted for current-year dollars based on the GEMSET projected implicit price deflator (IPD).

Exhibit 3-3
Fuel Prices Estimated as a Function of GEMSET Baseline Fuel Price Scenarios

Fuel	Fuel Price
Blast Furnace Gas	0.43 x Natural Gas
Coke Oven Gas	0.45 x Natural Gas
Distillate Fuel	1.0 x No. 2 Fuel Oil
No. 4 Fuel Oil	0.82 x No. 2 Fuel Oil
Jet Fuel	1.08 x No. 2 Fuel Oil
Kerosene	1.1 x No. 2 Fuel Oil
Propane	1.0 x Natural Gas
Waste Process Gas	0.43 x Natural Gas

Exhibit 3-4
Fuel Prices Held Fixed in All Scenarios (2002 Dollars)

Fuel	Fuel Price	Basis for Price Estimate
Agricultural Byproducts	\$ 1.99 / 10^6 Btu	Same as Wood Waste
Bituminous Glob	\$ 0.26 / 10^6 Btu	Parsons Corporation Estimate
Black Liquor	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate
Culm	\$ 0.26 / 10^6 Btu	Parsons Corporation Estimate
Digester Gas	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate
Landfill Gas	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate
Municipal Solid Waste	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate
Petroleum Coke	\$ 0.80 / 10^6 Btu	Weighted Average of FERC Form 423 2001 Data for U.S.
Prepared Nuclear Fuel	\$ 0.39 / 10^6 Btu	Parsons Corporation Estimate
"Red Bag" Hospital Waste	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate
Refuse	\$ 0.73 / 10^6 Btu	Weighted Average of FERC Form 423 2001 Data for U.S.
Sludge Waste	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate
Sulfur (for chemical process plant)	\$ 0.00 / 10^6 Btu ***(sulfur presumed to be process feedstock charge, rather than fuel charge))***	Parsons Corporation Estimate
Wood	\$ 1.99 / 10^6 Btu	Weighted Average of FERC Form 423 2001 Data for U.S.
Wood Waste (Solids)	\$ 0.73 / 10^6 Btu	Same as Refuse
Wood Waste (Liquid)	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate
Water for Hydroelectric	\$ 0.00 / 10^6 Btu	Parsons Corporation Estimate

3.4 Financial Considerations

As with any assessment of new generating facilities, the actual cost of production and the carrying charges associated with the capital expenditures for such units must be considered. In the following sections, those implications are discussed to provide the background for the actual comparison of the differing types of generation. The methodology employed in the analysis consists of the following:

- Prices for electricity are estimated two ways, either:
  - Based on an 'avoided cost' concept; or,
  - Based on an estimate of competitive prices under a market similar to that in PJM.

- Prices of CO_2 were determined based on current prices which are a function of the price of oil.

- Capital costs are developed for each scenario considered in the analysis. These costs were assumed to begin in 2006 and end at the beginning of 2010.

- All operating costs, including fuel, operation and maintenance, and fixed costs were developed for each scenario.

- Once these revenues and costs are determined, the financial analysis then evaluates the project on the same type of financial basis expected of a privately-held entity.

3.4.1 Fuel and Production Cost Calculations

For 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. The heat rate is an indication of the efficiency of that unit. The lower the heat rate, the more efficient the 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:

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

This capacity factor is a function of the load and hours the unit actually operated over a period of time. As an example, either of the two situations below would have the same capacity factor of 50% for the year:

- If units operated at its nameplate rating for half the hours in a year and were idle the remainder of the year.

- If a unit operated at 50% of its rated load for every hour of the year.

The accumulated hours of operation times the unit's load for each hour indicate the actual output of the unit in kWh. To obtain the amount of fuel used by that unit, the output times the average heat rate provides the amount of fuel used in Btu's over the time frame. Since fuel is priced as a function of Btu's (generally $\$/10^6$ Btu), the total fuel cost can then be calculated.

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. This total cost is then divided by the output to obtain a cost/kWh for that unit. For calculation simplicity, part load assessment of each unit is avoided. An average heat rate for the unit for the year is used rather than an incremental heat rate depending on a percentage of its rated capacity. In this fashion, nameplate output is used, and capacity factor is assumed to represent the fraction of the year the unit runs.

In subsequent sections, various graphs and tables will be presented for the several primary units under investigation, and compared against a combined cycle natural gas fired unit. In each case, the functions that are analyzed are heat rate, size, and capacity factor.

3.4.2 Operating and Maintenance Costs

Another cost component that must be identified for this analysis is the variable cost of operating the unit 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. The fuel prices are then escalated as per the projections shown in the GEMSET Fuels Characterization, while the O&M factor is increase by the IPD through the study horizon.

As mentioned, each unit will have its own set of circumstances that come into the calculation. However, the use of a standard cost by type of unit is within normal actual cost parameters for generating stations, and is considered acceptable for this type of analysis.

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

As mentioned in the Summary, the electric price that the IGCC+S can be expected to receive for its generation is based on two methodologies. This first methodology is described in this subsection; the other method is described later in Section 3.6,"Method 2 – Projecting Electric Price and Revenue Based on a Competitive Market."

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, they are taking 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 the fuel cost is the major component of the operating costs, 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 at about $3.50/Mcf (about $3.50/$10^6$ Btu). After adding a small component for fixed and other variable O&M, today's price is estimated to be around $45.00/MWh.

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 IPD to adjust for general installation. In Exhibit 3-5 the total avoided cost price of electricity is presented as utilized in the analysis as the price available to the IGCC+S in California.

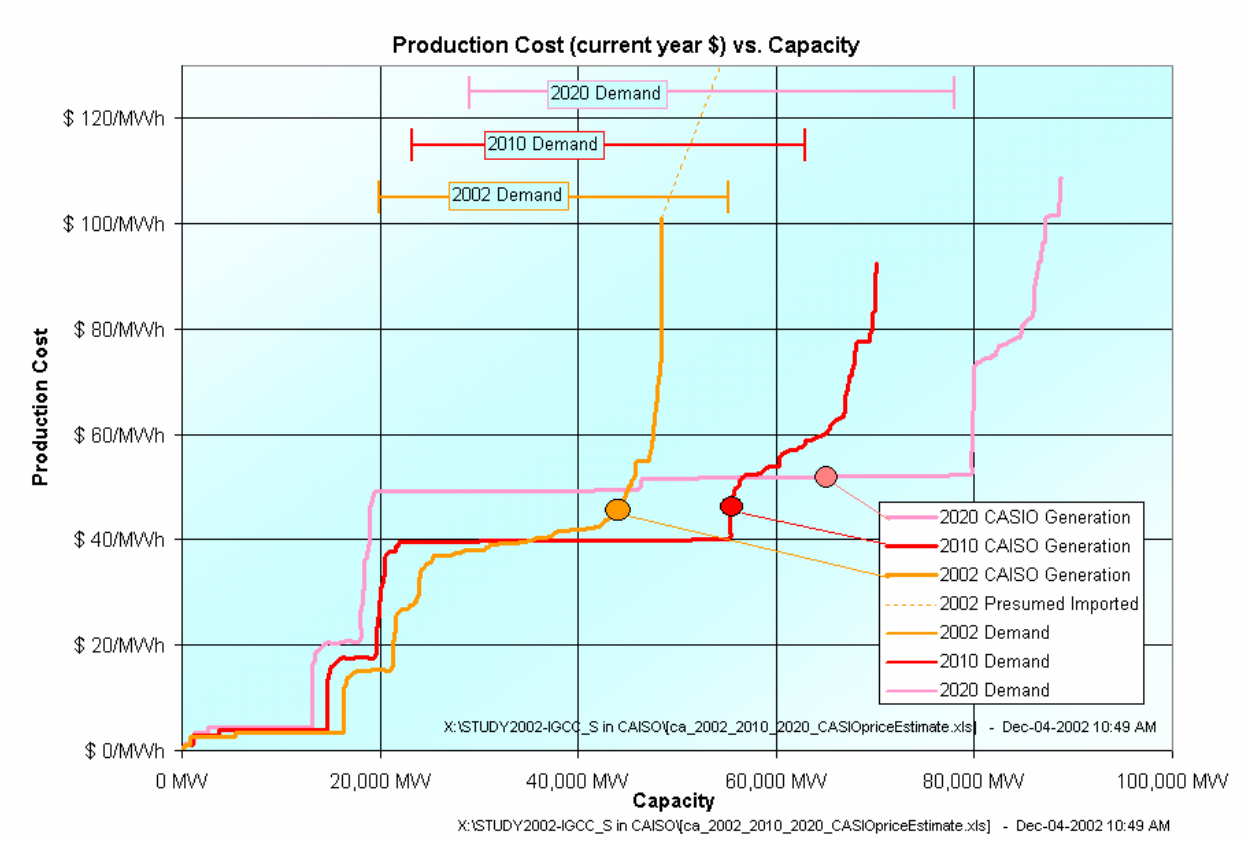
Exhibit 3-5
Electric Price Based on Avoided Cost for NGCC

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

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

In the second method for estimating price, the demand profile and growth in generation establishes the individual units in the CAISO generation fleet in each year. The GEMSET Team then established the heat rate of these units, and using the fuel price and GEMSET estimates of variable operating costs, the GEMSET Team was able to establish a production cost for every unit expected available in year 2002, 2010, and 2020. Based on these estimated production costs, the fleet in each of these years was stacked; yielding a production cost for every demand level in each year. Exhibit 3-6 presents these production costs utilized in the development of electric prices in California.

Exhibit 3-6
GEMSET Assumption of Production Cost Stacking versus Demand by Year in CAISO



3.6.1 Handling the Randomness of Competitive Market Effects In Order to Forecast Alternate Scenarios

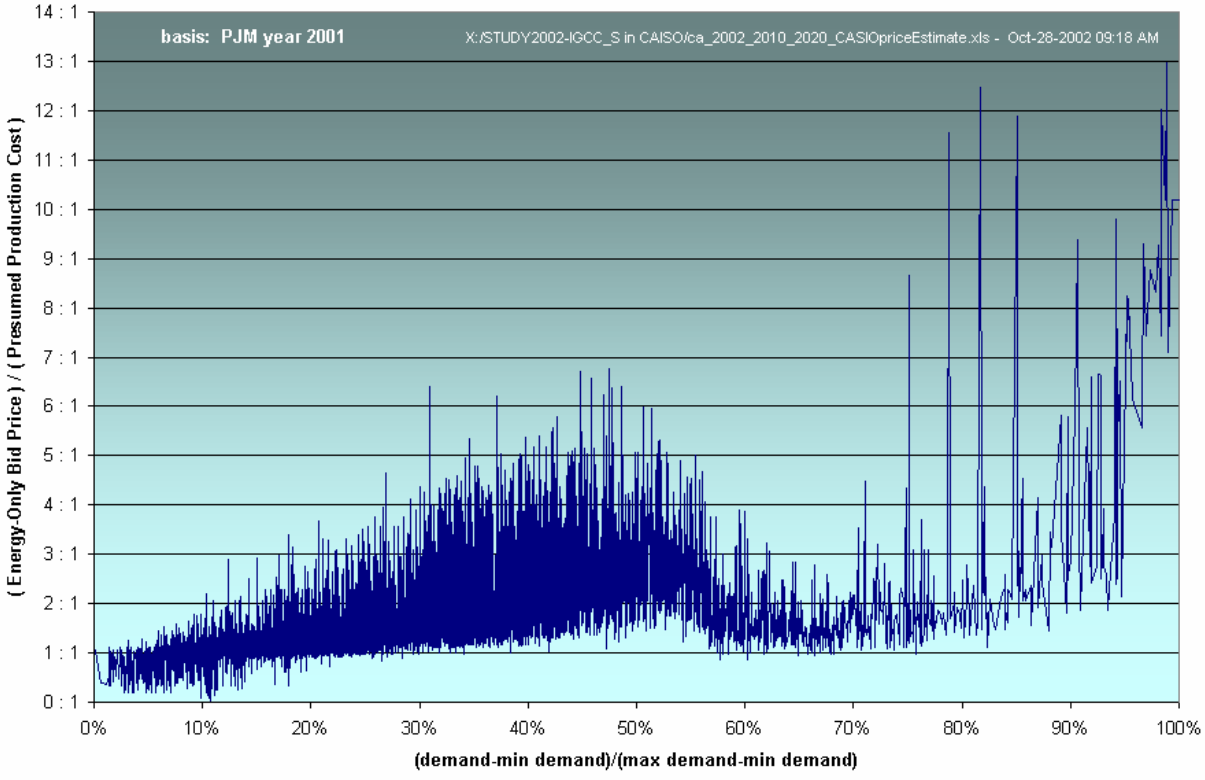
While threshold bid price is an important driver for bid price, in a competitive market there are many reasons why bid price varies. It is assumed that these "gamesmanship" effects are random, and driven by competition; however, it is assumed that on average the competitive gamesmanship market variability of cost versus bid price that actually occurred in the prior year will likely be similar to that in any given scenario.

In GEMSET, an "inferred competition ratio" was established for each hour of the year, and assumed in the aggregate to reasonably approximate competitive variability in other years and scenarios. This ratio maps hour-by-hour the estimated threshold bid price for each hour's demand level and establishes the ratio between cost to the actual day-ahead price in that hour. That hour-by-hour baseline inferred competition ratio is then used to map all future scenarios. It is assumed that while any given hour is random, the aggregate trend of competitive pressures will over a year range through similar variations. That is, while an individual hour cannot be predicted with any accuracy due to the random nature of competition, still, over 8,760 hours, the amount of variability between price and demand are more likely to be similar on average.

Electricity sales in the CAISO this past year have been by bilateral sales agreement, so the current prices being paid by CAISO are not publicly available. In order to project how these sales might be priced, the GEMSET Team made the presumption that the prices were set in an unmanipulated market. In order to set these prices, a method of mapping the hour-by-hour "random walk" in energy price is needed. The GEMSET Team assumes that the randomness exhibited by another large competitive market could be used to map the randomness between production cost and price. The ratio of energy-only[§] price to production cost is called the "competitive factor." The competitive factor for PJM in year 2002 was used,[3] and mapped versus percentage of demand spread, as shown in Exhibit 3-7.

The decision to map this competitive factor versus percentage of demand recognizes that at times of very low demand, bids sometimes are even below production costs to keep units running rather than to shut them down, while at times of high demand, there is higher profit taking. From the random variability shown in Exhibit 3-7, it would appear that this PJM market is not manipulated, so the PJM competitive model was judged a reasonable forecast tool to assess likely hour-by-hour variations in price in other competitive markets, such as the California market forecast here.

Exhibit 3-7
Year 2002 Competitive Factor for PJM

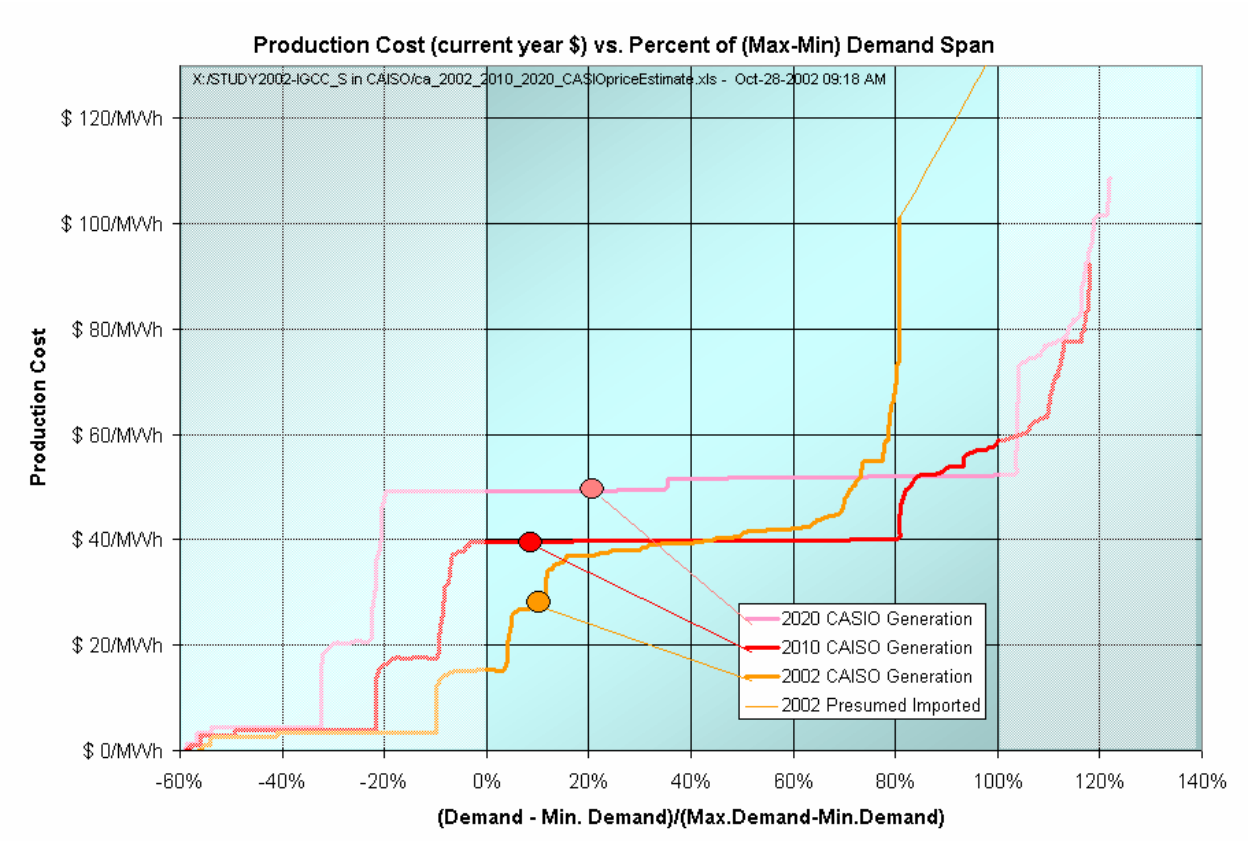


[§] Energy-only price is the price paid for wholesale kWh electric sales; there are other revenue streams possible to a generating company owner, such as capacity revenue, and revenue from the sale of various ancillary services

To use these factors, the year 2002, 2010, and 2020 production cost curve, Exhibit 3-6, is mapped into percentage of demand, as shown in Exhibit 3-8. Notice that the available generation in year 2002 is less than the peak demand, that is, it imports from outside the CAISO region had to make up the shortfall. The GEMSET Team used a conservative straight-line presumption of costs for the marginal units supplying peak demand from outside the region, as shown in Exhibit 3-8. The demand projections for years 2010 and 2020 were met with a fleet that supplies all CAISO demand plus reserve needs with units within the region.

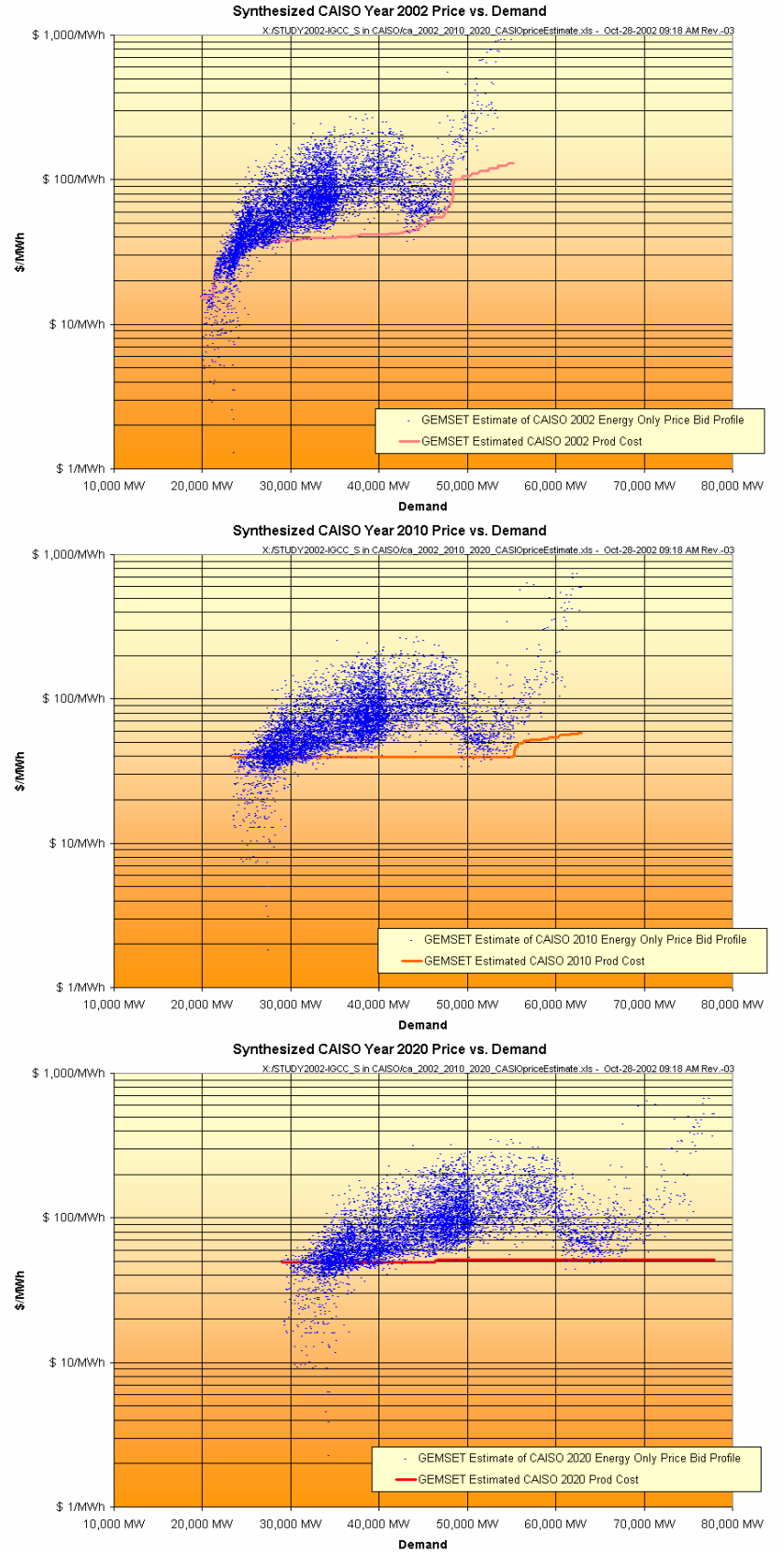
Notice that the presumption about how the load growth will be accomplished in the CAISO leaves a very unusual demand profile in California. The maximum feasible amount of renewable generation was added, but even those optimistic expansion assumptions still leave the majority of new generation provided by combined cycles and gas turbine peakers, Exhibit 3-8. There is no hydroelectric power to develop, and there has been no new coal or nuclear units in these projections, in keeping with the types of units installed in the State of California. It is evident from the 2010 and 2020 projections under this presumption that the state is woefully short in "traditional" baseload generation found in other regions that we by contrast anchored by nuclear and coal-fired capacity. The existing baseload capacity of the state is all absorbed just meeting minimum demand; the low-cost "flat" area to the left of the exhibit. Whereas most other regions would have their minimum load met by nuclear and coal units, in year 2010 and 2020, units that otherwise be in intermediate load service in any other region, in California are placed in baseload service. It will be evident later, that this has profound price implications for the price of electricity expected for the state.

Exhibit 3-8
GEMSET Estimate of CAISO Production Costs vs. Percentage of Demand Span for Years 2002, 2010, and 2020



Using the calculated PJM competitive factor, Exhibit 3-7, mapped against the estimated production costs, Exhibit 3-8, an estimate can then be made of the energy-only costs versus hour-by-hour demand in the CAISO region for each year. This results in a "random walk" of price versus demand for each year, as shown in the "dots" of Exhibit 3-9. Also shown is the map of calculated production costs, as the solid line in each year's plot.

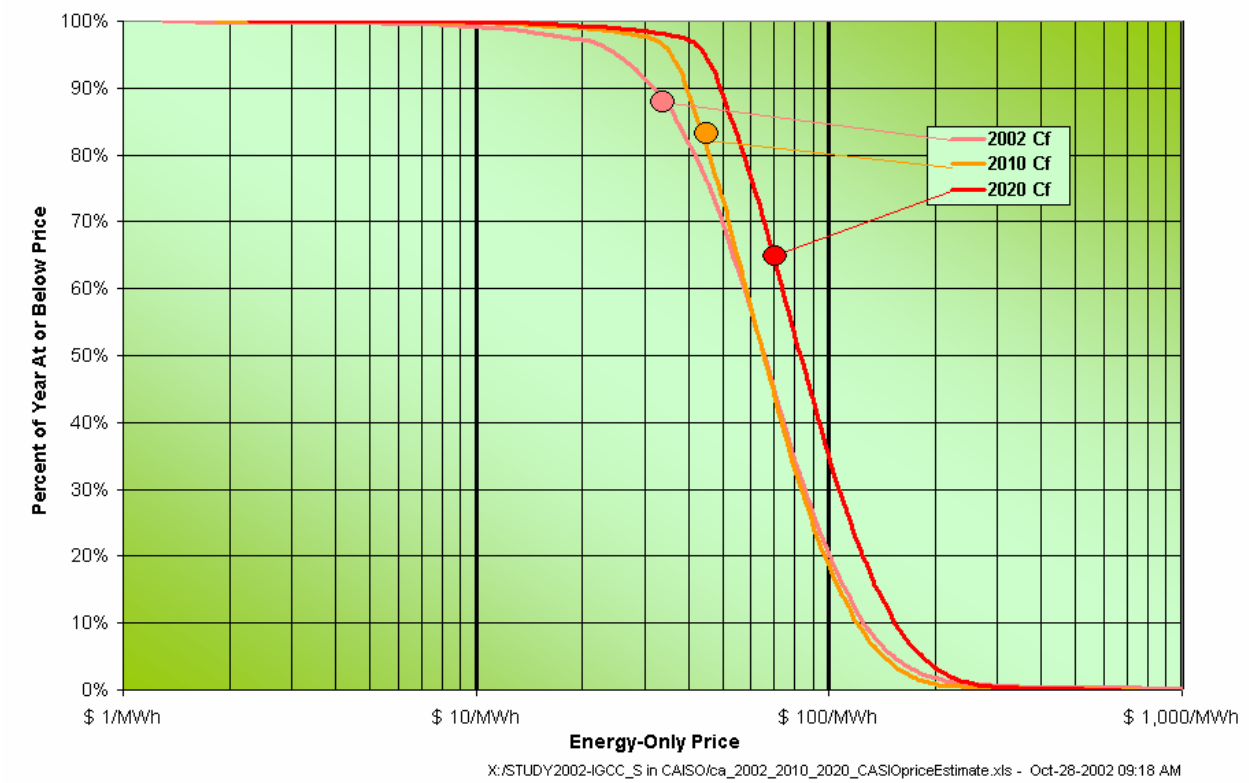
Exhibit 3-9 Price vs. Demand Projected for Years 2002, 2010, and 2020



3.6.2 Method 2 Estimate of Electric Price and Revenue

A histogram of energy-only electric price versus percentage of the year at or below that price can then be developed from these data. This is shown in Exhibit 3-10.

Exhibit 3-10
GEMSET Energy-Only Price Histogram for CAISO in Years 2002, 2010, and 2020



The implications of this inadequate level of baseload generation to California would be profound. The electric users in the state will have become captive to the volatility of the natural gas market. Were this construction presumption to develop as was forecast here, the state's electric customers could suffer electric price volatility during times of peak gas use. It would be imperative that adequate firm pipeline capacity be developed to assure electric production during peak gas demand periods. The high prices shown here for generation will encourage baseload capacity located in other states being sold into the California market. This could have the effect of diluting the potential return of natural gas generation investors within the state. It would be important that long-term firm transmission and generation capacity be assured for such out-of-state baseload generation, otherwise, construction of necessary in-state capacity might be suppressed when the lower-cost import energy is supplied, leaving a vacuum should it no longer be available. The solution for the State of California would be to build coal or nuclear baseload capacity within the state, a future not foreseen by this near-exclusive natural-gas-dominated future assessment. There would be considerable opportunity for a coal or nuclear plant owner to build within the state, if such a unit could be sited under the very stringent environmental and licensing circumstances that exist in California today.

The relationship in each year is thus established of production cost histogram, which would yield the expected capacity factor of a unit, and the energy-only revenue histogram, which yields the energy price received. As an example, see the year 2002 situation, Exhibit 3-11, which compares the production cost histogram to the price histogram. Note that these two histograms are not time-coincident. Each represents a separate time interval for each point (as is evident from the scatter of the blue dots in Exhibit 3-9); do not try to relate the capacity factor to the price duration. Knowing the capacity factor that can be earned by a unit, from its production cost stacking order, and the production cost duration histogram, you can then establish the expected revenue, by integrating the price curve from the capacity factor intercept of the price duration histogram to the right, that is, the unit once dispatched earns the marginal revenue of the most costly unit dispatched for every higher priced hour throughout the year, Exhibit 3-12.

Exhibit 3-11 GEMSET 2002 Production Cost and Energy-Only Price Histograms

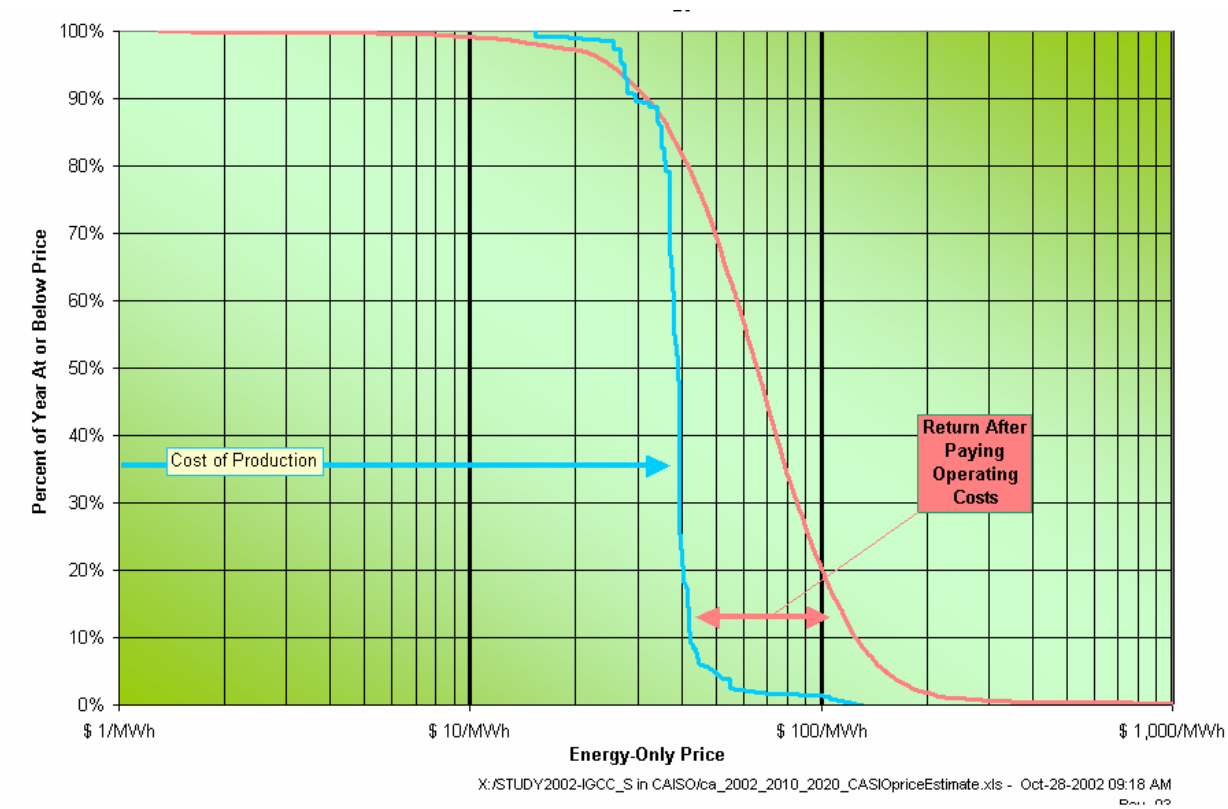
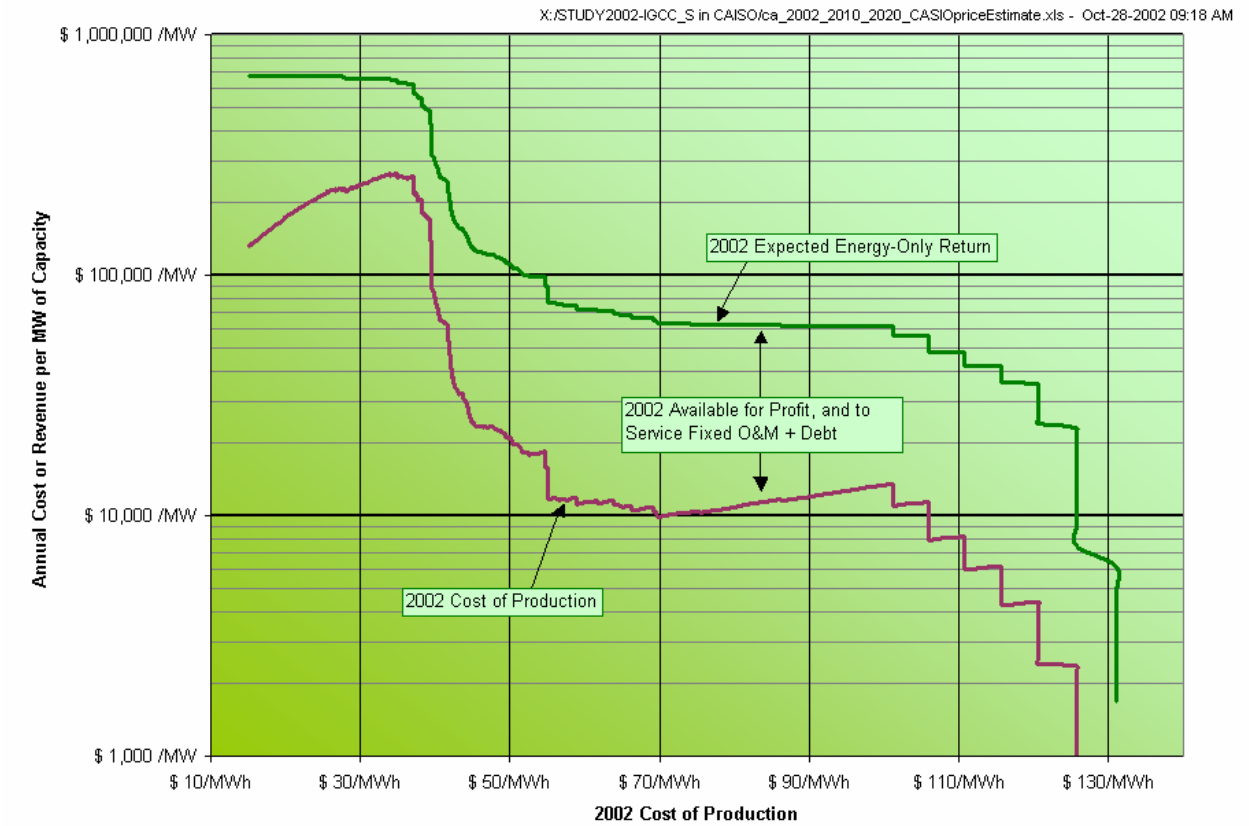
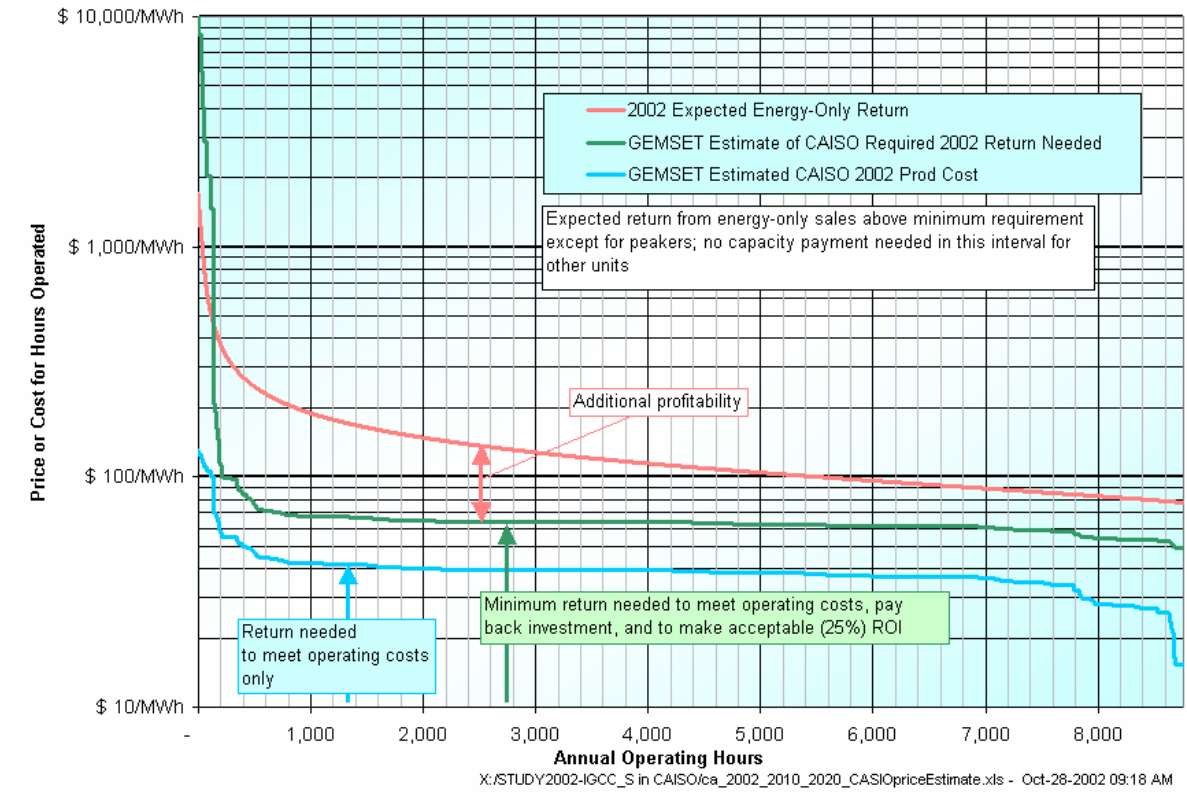


Exhibit 3-12 2002 Integrated Revenue Compared to Production Cost



Are there other likely revenue streams for these units? Perhaps. Certainly there might be revenue from capacity, and from the sale of ancillary services. A check of whether the energy-only power sales would be sufficient to fairly compensate an owner for the carrying charges; if yes, the GEMSET Team feels it would be unlikely that CAISO (or FERC Standard Market Design) would compensate owners for capacity. The GEMSET Team evaluated the expected return from energy only sales, and found them adequate; for example, the year 2002 situation is shown in Exhibit 3-13. Energy-only sales under the presumptions made here are expected to provide adequate return, so there is no need for capacity payments, and no allowance for capacity payments was made in the financial assessments.

Exhibit 3-13
2002 Energy Only Sales vs. Requirement for Acceptable Return Investment



Dispatch of IGCC+S Would Be So Good, Unit Dispatch Would Be Limited By Availability, Not Economics of Operration. There is now sufficient information to develop the revenue expected for IGCC+S units operating in the CAISO for years 2002, 2010, and 2020. Given the production cost of a unit, the stacking order versus demand, the expectation of capacity factor can be established. For integrated gasification combined cycle (IGCC) with CO_2 sequestration (IGCC+S), production costs are low, Exhibit 3-14. This is because of the price of production is dominated by fuel cost, and coal is much less costly than natural gas. In addition, since California is so deficient in traditional baseload capacity, the IGCC units would dispatch no worse than 99.30% of the year in every year evaluated if only they were available to operate. Essentially, an IGCC+S would be so attractive to operate serving California, that such a unit would be dispatched whenever it was available to operate. As a practical matter, these units require annual maintenance, and would have some forced outage expectation. For this study, the GEMSET Team assumed that the equivalent availability of the units would be 85%, a reasonable average for coal-fired units in the U.S. Thus, the IGCC+S units are expected to operate at an 85% capacity factor, their dispatch limited only by their availability.

Revenue Expectation. Given these assumptions, the revenue from electric sales expected for these years is shown in Exhibit 3-14, compared to the revenue expected of CAISO units in the fleet that would dispatch at 85% capacity factor.

Exhibit 3-14
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		

X:/STUDY2002-IGCC_S in CAISO/ca_2002_2010_2020_CASIOpriceEstimate.xls - Oct-28-2002 09:18 AM Rev.-03

4. Market Study Assumptions for CO_2 Sales and IGCC Use Serving the Electric Needs of California

This section discusses the market assumptions used to model IGCC+S units in the California electric market, and to compare them to natural gas combined cycle units.

4.1 CO_2 Market Data and Assumptions

The sections below discuss the potential market for carbon dioxide (CO_2) for enhanced oil recovery, using the CO_2 captured from the IGCC+S plant. Section 4.1.1 discusses the California Market for Oil Well CO_2, while Section 4.1.2 discusses the New Mexico and West Texas Market for Oil Well CO_2.

4.1.1 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.[4] 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.[5] 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 screening criteria are shown in

Exhibit 4-1**.** Evaluation of the screened reservoirs with their CO_2 Predictive Model provided data for the parameters shown in Exhibit 4-2.

Exhibit 4-1
Physical Screening Criteria for Oil Reservoirs for CO_2 Flooding Applicability

Parameter	Criteria
Oil Gravity	> 22° API gravity
Oil Viscosity	< 10 cp
Oil Saturation	> 20%
Sandstone or Carbonate Depth	> 2500 ft if API > 40° > 2,800 ft if 32° ≤ API ≥ 40° > 3,300 ft if 28° ≤ API ≥ 32° > 4,000 ft if 22° ≤ API ≥ 28°

Exhibit 4-2
Parameters Evaluated for Screened Reservoirs

OOIP – Original Oil in Place
EOR – Oil Recoverable Due to CO_2 Flooding
CO_2 – P – Purchased CO_2 (Net CO_2)
GR CO_2 – Total CO_2 Injected (Gross CO_2)
RATIO – CO_2 – Purchased per Barrel of Oil Produced
ROR – Rate of Return

The results of the reservoir screening for all of California as provided by the NPTO, shown in Exhibit 4-3, 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 Exhibit 4-4). 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 Exhibit 4-3) satisfied the evaluation criteria, three of which are located in the San Joaquin Valley. Two of those fields, the Coalinga in Fresno County and Coles Levee North in Kern County, make up over 90% of the potential EOR via CO_2 flooding in the Valley. The EOR potential of these two fields is estimated to be about 156 million barrels of oil, representing about 12% of the original oil in place (OOIP). The purchased CO_2 per barrel of oil is estimated to be about 10,000 standard cubic feet (scf), within the range others have reported as typical[6], resulting in a total purchased-CO_2 requirement of about 1,560 billion scf to recover the 156 million barrels of oil from the fields. 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.

The authors of a recent paper on the profitability of EOR via CO_2 flooding provided a rule-of-thumb that a reservoir having at least 100 million barrels of OOIP would be needed to profitably flood the reservoir unless you are beneath an existing CO_2 line.[7] They also indicated that generally, the price of CO_2 needs to be about 3 to 4% of the oil price in $/bbl, and that if they could get CO_2 to the large fields in California for $1 per thousand cubic feet (Mcf), then they think that an operator could make money.

Both the Coalinga and Coles Levee North oil fields in the San Joaquin Valley are reported by the NPTO to have an 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, as discussed in Section 5.2, 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, the cost to collect and transport the CO_2 to the oil fields would meet the $1/Mcf target. The $0.35/Mcf CO_2 transportation cost may be quite conservative since it is based on the Cortez Pipeline tariff to transport CO_2 502 miles from Cortez Colorado to Denver City in west Texas. Utilizing the Massachusetts Institute of Technology (MIT) Pipeline Transport Model, discussed in more detail in Section 5.2, 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. However, using the higher transportation cost for the assessment will bring more oil fields in California into the range of transport.

Exhibit 4-3
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		

Exhibit 4-4
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. The more detailed assessment should account for anticipated oil price variation over the 2010 to 2020 period projected by GEMSET. Future assessments should also consider EOR from oil fields producing oil with API gravities less than 22°, and the applicability of immiscible CO_2 flooding for the heavier oils produced in the San Joaquin Valley.

4.1.2 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.[8] A review of the Texas Railroad Commission Texas Oil Industry Statistics[9] 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.[10] 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.

A study by the Bureau of Economic Geology in Texas (1999) examined the potential for capturing CO_2 from a group of 37 coal- and lignite-fired power plants and using it for EOR. The study identified over 1700 significant reservoirs in the state that could be used to sequester power plant CO_2 while enhancing oil production in areas of Texas far from the existing CO_2 delivery infrastructure. A total of 3 billion barrels of residual oil was determined to be recoverable through CO_2 injection within 30 miles of candidate power plants. This increased to 6 billion barrels within 60 miles of candidate power plants, and 8 billion barrels within 90 miles.

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 in Exhibit 4-1 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 Exhibit 4-5. 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.

Exhibit 4-5
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

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 Error! Not a valid bookmark self-reference..

Exhibit 4-6
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**

Based on the preliminary screening and evaluations, the EOR potential of these fields in combination with the New Mexico fields, shown in Exhibit 4-7, 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.

Exhibit 4-7
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**

4.2 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)[11]. The baseline design (Case 3-E in Reference 11) 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 both the San Joaquin Valley, CA, IGCCs and the Four Corners, NM, IGCCs.

4.2.1 IGCC Plant Performance

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 conditions associated with the three sites are compared in Exhibit 4-8. The Illinois No. 6 and Wyodak coal properties are compared in

Exhibit 4-9. These adjustments are approximate, and if this project were to be pursued, the GEMSET Team would recommend rigorous heat and mass balance analysis to verify the adjustments.

Exhibit 4-8 Site Conditions Comparison

Condition	Mid-USA	San Joaquin Valley, CA	Four Corners, NM
Site Elevation	500	236	5,333
Ambient Pressure, psia	14.4	14.4	12.4
Dry Bulb Temperature, °F	63	63	48
Relative Humidity, %	55	53	52
Extreme Low Temperature, °F	20	14	1
Extreme High Temperature, °F	95	115	100

Exhibit 4-9
Coal Properties Comparison

	Illinois No. 6 Coal[12]		Wyodak PRB Coal	
Proximate Analysis	**As-Rec'd Basis**	**Dry Basis**	**As-Rec'd Basis**	**Dry Basis**
Moisture	11.12	0	26.6	0
Volatile Matter	34.99	39.37	33.2	45.23
Fixed Carbon	44.19	49.72	34.4	46.87
Ash	9.70	10.91	5.8	7.90
Ultimate Analysis				
Sulfur	2.51	2.82	0.6	0.82
Hydrogen	5.74	5.06	6.5	4.82
Carbon	63.75	71.72	50.0	68.12
Nitrogen	1.25	1.41	0.9	1.23
Oxygen	16.77	7.75	36.2	17.11
Ash	9.70	10.91	5.8	7.90
Heating Value, HHV	11,666	13,126	8,630	11,757

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 Exhibit 4-10.

Exhibit 4-10
IGCC Plant With CO_2 Capture Performance Comparison

	Baseline Case 3-E	San Joaquin Valley, CA	Four Corners, NM
Coal	Illinois #6	Wyodak PRB	Wyodak PRB
Turbo-Set Power Output, kW	465,474	465,474	386,343
Fuel Gas Expander Power, kW	8,801	8,801	7,305
Gross Power Output, kWe	474,275	474,275	393,648
Auxiliary Power			
Coal Handling & Grinding, kW	1,190	1,600	1,330
Slag Handling & Dewatering, kW	160	130	110
Gas Cleanup, kW	8,690	3,200	2,680
HP CO_2 Compressor, kW (Note 1)	26,850	27,770	23,050
Balance of Auxiliary Power, kW	53,250	53,250	41,900
Total Auxiliary Power, kWe	90,140	85,950	69,070
Net Power Output, kWe	384,135	388,323	324,580
Heat Rate, Btu/kWh HHV	9,705	9,600	9,533
Net Plant Efficiency	35.2 % HHV 36.8 % LHV	35.6 % HHV 37.4 % LHV	35.8 % HHV 37.7 % LHV
Coal Feed, 10^6Btu/h	3,728	3,728	3,094
Coal Feed, lb/h	319,560	431,980	358,543
Ash/Slag Production, lb/h	31,811	25,055	20,796
Sulfur Production, lb/h	7,989	2,582	2,143
CO_2 Produced from Coal, lb/h	746,972	791,963	657,329
CO_2 Captured @ 90%, lb/h	681,404	712,767	591,596
CO_2 Emissions, lb/h	65,568	79,196	65,733

Note 1 – Final CO_2 pressure of 2,200 psia

The site conditions used for the San Joaquin Valley are nearly identical to the mid-USA conditions assumed for the baseline Case 3-E site. As such, the gas turbine power is unaffected and the differences in the IGCC plant performance are based solely on coal property differences.

The Wyodak PRB coal is higher in moisture, significantly reducing its higher heating value. Therefore, more coal must be fed to the system to obtain the same thermal energy input, increasing coal handling requirements and CO_2 generation. On the other hand, the ash and sulfur content of the Wyodak PRB coal are significantly lower than the Illinois No. 6 coal, and the auxiliary power associated with the addition of the H_2S polishing system to meet the anticipated California SO_2 emissions standards is minimal. Therefore, the ash handling and sulfur removal power requirements for the IGCC using Wyodak PRB coal are significantly lower than the IGCC using Illinois No. 6 coal. The net effect is a reduction in auxiliary power requirements for the plant powered by the Wyodak PRB coal, and thus an increase in net thermal efficiency (decrease in net heat rate).

The high elevation 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.[13] 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%. The lower ambient temperature results in a negligible change in heat rate. Power reduction due to ambient temperature in the GE paper is not directly applicable to the H turbine.

4.2.2 IGCC Plant Environmental Emissions

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.[14] 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 Exhibit 4-11.[15] 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).[16] 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.[17]

Exhibit 4-11
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 15

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)

An IGCC+S plant based on the configuration selected by Parsons for the EPRI/DOE study would not meet the ARB's SO_2 and NOx standards, and may not meet the PM_{10} standard based on the sulfur concentration in the syngas, although the configuration would meet the federal New Source Performance Standards (NSPS). Therefore, a fixed-bed H_2S polishing system using ZnO as the reagent was added to the configuration upstream of the gas turbine, and an SCR was added downstream of the heat recovery system for NOx control. The expected emissions prior to and after the addition of the H_2S polishing system and SCR NOx control system are shown in Exhibit 4-12. 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 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 NO_2 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.

Exhibit 4-12
NO_2, 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			
	NO_2	**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

4.2.3 IGCC Plant Costs

The capital and O&M costs for the systems comprising the IGCC 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 SRC NOx control systems were estimated by adjusting the cost estimates developed for the EPRI/DOE study in Reference 11 based on the differences in performance characteristics presented in Exhibit 4-10. 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[18]. 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 in Exhibit 4-13. The unit fixed O&M costs in current-year dollars per kilowatt and variable O&M costs in current-year dollars per megawatt-hour (net) are summarized for the San Joaquin Valley IGCC plant with and without CO_2 removal in Exhibit 4-14 and Exhibit 4-15. The O&M costs for the Four Corners IGCC plant with and without CO_2 removal are summarized in Exhibit 4-16 and Exhibit 4-17. Details of the costs estimates are discussed in the sections that follow.

Exhibit 4-13
IGCC Plant Capital Cost Summary (Current Year $/kW)

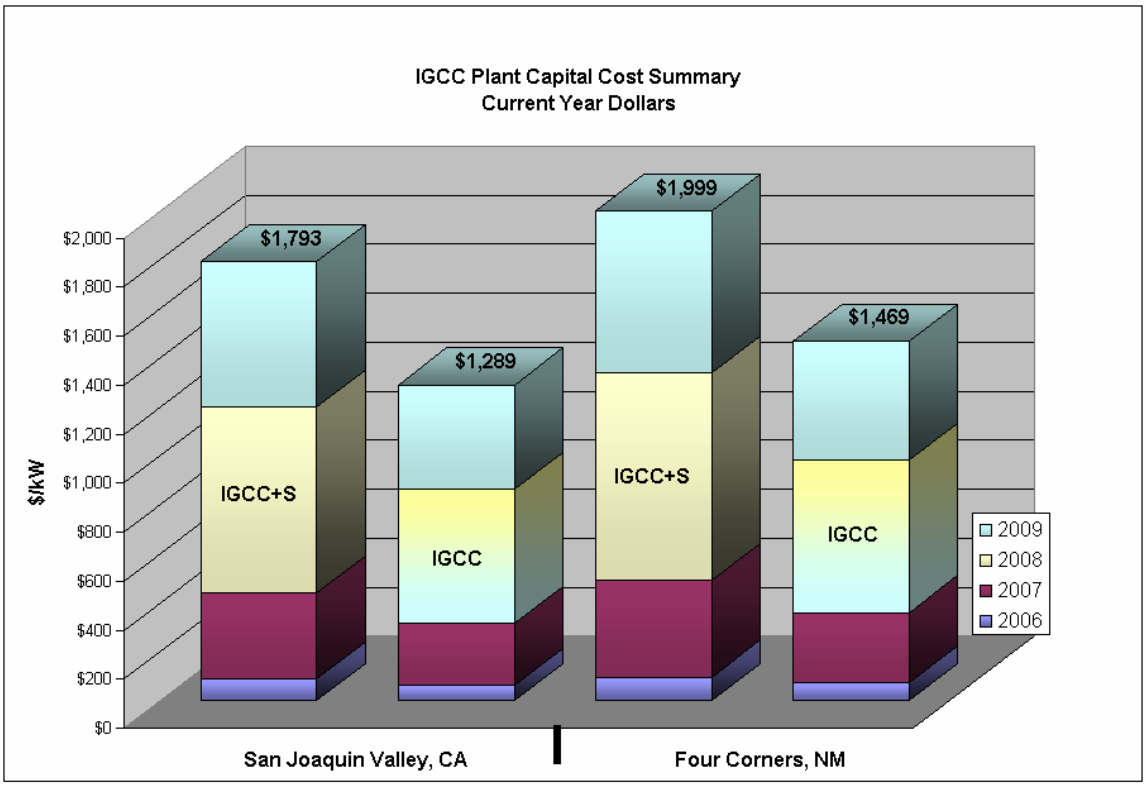


Exhibit 4-14
San Joaquin Valley IGCC Fixed O&M Cost Summary (Current-Year $/kW/y)

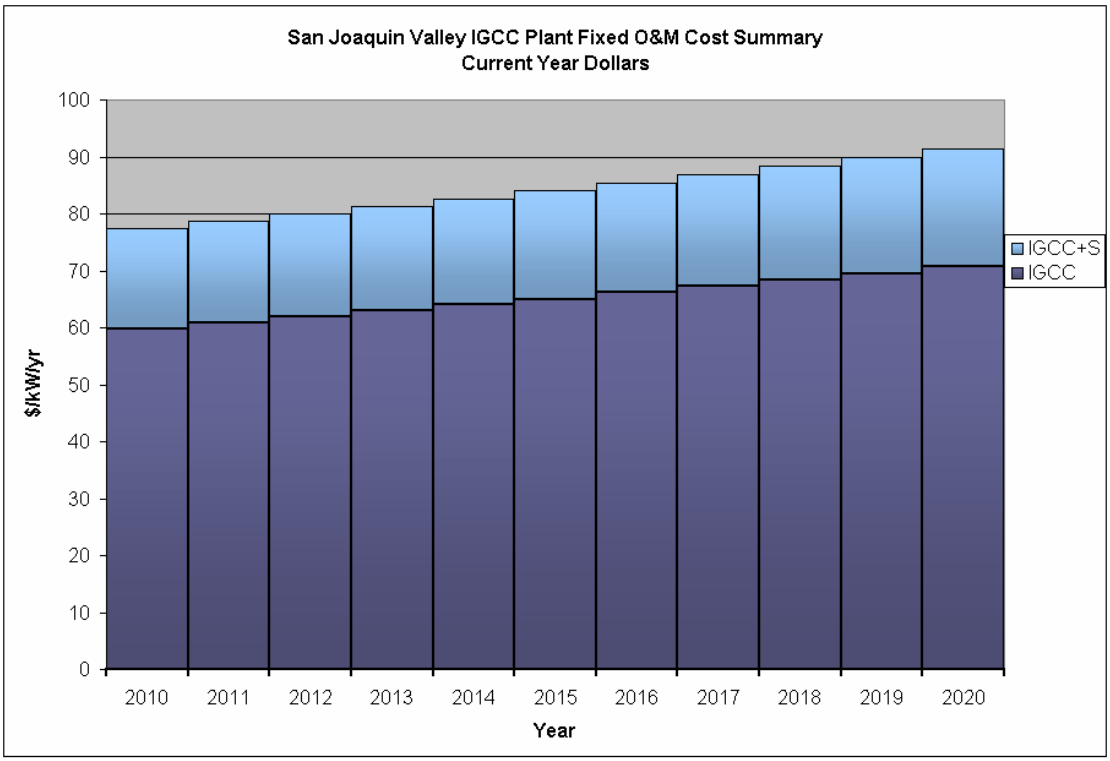


Exhibit 4-15
San Joaquin Valley IGCC Variable O&M Cost Summary (Current-Year $/MW$_{net}$-h)

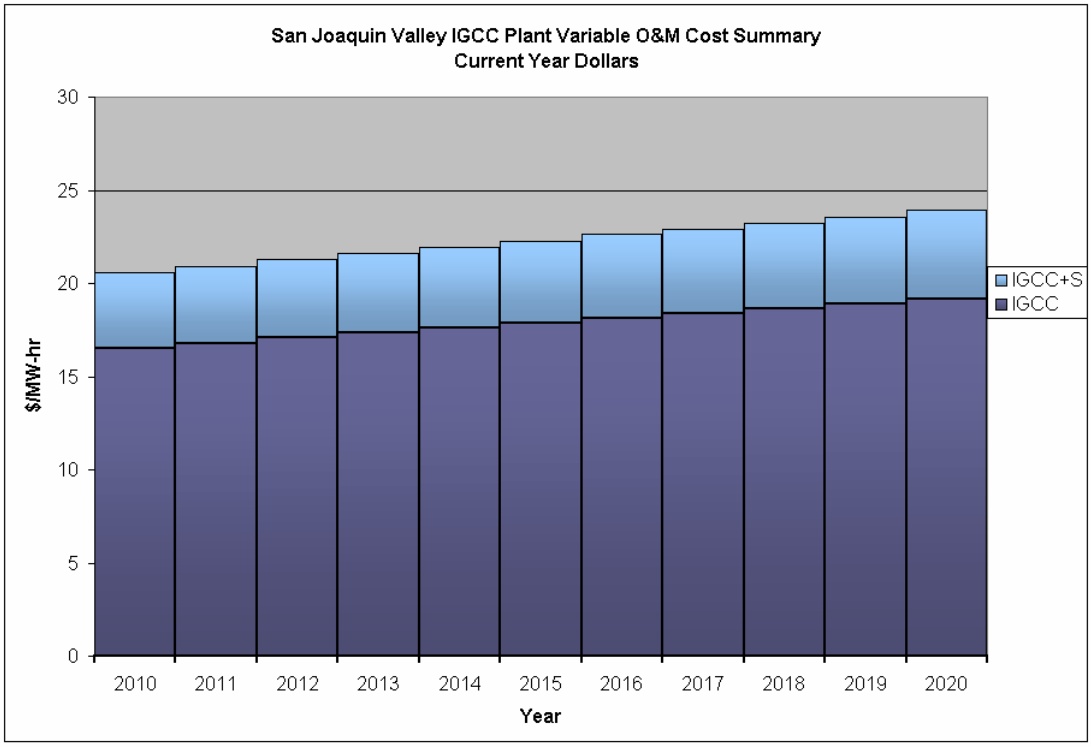


Exhibit 4-16
Four Corners, NM IGCC Fixed O&M Cost Summary (Current-Year $/kW/y)

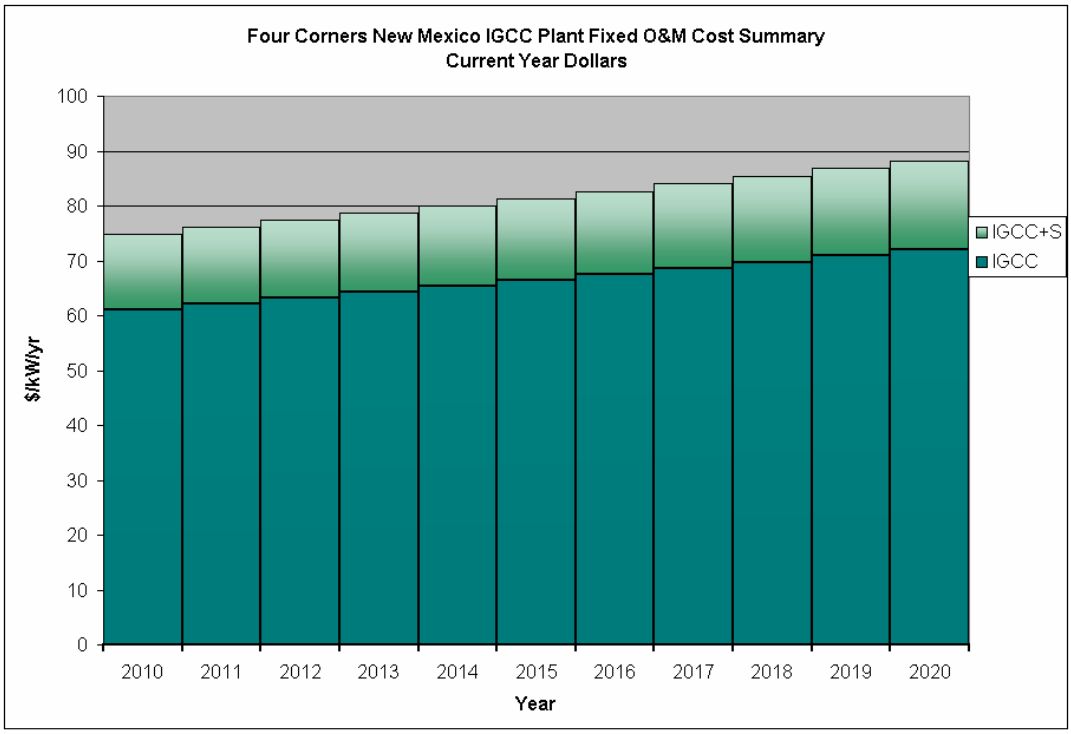
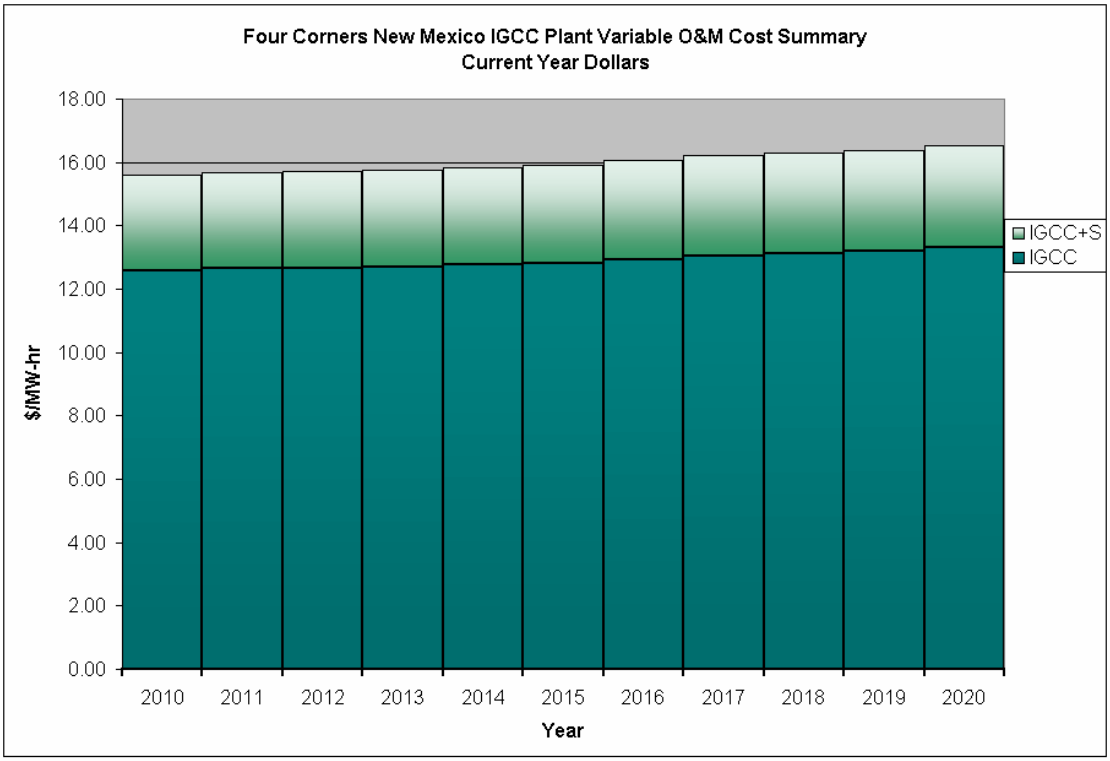


Exhibit 4-17
Four Corners, NM IGCC Variable O&M Cost Summary (Current-Year $/MW$_{net}$-h)



4.2.4 IGCC Plant Capital Costs

The plant capital costs were first estimated in 1999 dollars, consistent with the baseline plant cost year in the DOE/EPRI study, and then adjusted to current-year dollars for the four year construction period beginning in 2006 based on the ratios of the GEMSET projected implicit price deflator (IPD), as shown in Exhibit 4-18. The capital cost values in 1999 dollars for the Four Corners, New Mexico, and San Joaquin Valley IGCC plants with CO_2 removal (IGCC+S plants) are compared to the baseline Case 3-E estimates in Exhibit 4-19. The capital costs for the Four Corners and San Joaquin Valley IGCC+S plants in current-year dollars for plants beginning operation in 2010 are presented in Exhibit 4-20. 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 Exhibit 4-13, is lower because of the higher net power generation of the San Joaquin Valley plant.

Exhibit 4-18
GEMSET Projected Implicit Price Deflator

Source: Reference

GIPD-2002-04-01 x:/GEMSET model/GEMSETimplictPriceDeflator.xls historical current to 01-Apr-2002					
Approx. Quarter Ending	GNPDEF IPD	Approx. Quarter Ending	GNPDEF IPD	Approx. Quarter Ending	GNPDEF IPD
31-Mar-96	99.39	29-Sep-04	115.06	1-Apr-13	132.43
30-Jun-96	99.74	30-Dec-04	115.54	1-Jul-13	132.97
29-Sep-96	100.22	1-Apr-05	116.02	30-Sep-13	133.52
30-Dec-96	100.63	1-Jul-05	116.50	31-Dec-13	134.08
1-Apr-97	101.33	30-Sep-05	116.98	1-Apr-14	134.63
1-Jul-97	101.80	31-Dec-05	117.47	1-Jul-14	135.19
30-Sep-97	102.10	1-Apr-06	117.96	30-Sep-14	135.75
31-Dec-97	102.46	1-Jul-06	118.44	31-Dec-14	136.31
1-Apr-98	102.73	30-Sep-06	118.93	1-Apr-15	136.88
1-Jul-98	102.98	31-Dec-06	119.43	1-Jul-15	137.44
30-Sep-98	103.34	1-Apr-07	119.92	30-Sep-15	138.01
31-Dec-98	103.62	1-Jul-07	120.42	31-Dec-15	138.58
1-Apr-99	104.08	30-Sep-07	120.91	31-Mar-16	139.16
1-Jul-99	104.42	31-Dec-07	121.42	30-Jun-16	139.73
30-Sep-99	104.77	31-Mar-08	121.92	29-Sep-16	140.31
31-Dec-99	105.18	30-Jun-08	122.42	30-Dec-16	140.89
31-Mar-00	106.18	29-Sep-08	122.93	1-Apr-17	141.48
30-Jun-00	106.76	30-Dec-08	123.44	1-Jul-17	142.06
29-Sep-00	107.27	1-Apr-09	123.95	30-Sep-17	142.65
30-Dec-00	107.74	1-Jul-09	124.47	31-Dec-17	143.25
1-Apr-01	108.60	30-Sep-09	124.98	1-Apr-18	143.84
1-Jul-01	109.16	31-Dec-09	125.50	1-Jul-18	144.43
30-Sep-01	109.77	1-Apr-10	126.02	30-Sep-18	145.03
31-Dec-01	109.72	1-Jul-10	126.54	31-Dec-18	145.63
1-Apr-02	110.06	30-Sep-10	127.06	1-Apr-19	146.23
1-Jul-02	110.86	31-Dec-10	127.59	1-Jul-19	146.84
30-Sep-02	111.32	1-Apr-11	128.12	30-Sep-19	147.44
31-Dec-02	111.79	1-Jul-11	128.65	31-Dec-19	148.06
1-Apr-03	112.25	30-Sep-11	129.18	31-Mar-20	148.67
1-Jul-03	112.71	31-Dec-11	129.72	30-Jun-20	149.28
30-Sep-03	113.18	31-Mar-12	130.25	29-Sep-20	149.90
31-Dec-03	113.65	30-Jun-12	130.79	30-Dec-20	150.52
31-Mar-04	114.12	29-Sep-12	131.33		
30-Jun-04	114.59	30-Dec-12	131.88		

Exhibit 4-19
IGCC Plant With CO_2 Capture Capital Cost Comparison (Million Fixed-Year 1999 Dollars)

Capital Cost Category	Baseline Case 3-E	San Joaquin Valley, CA	Four Corners, NM
Coal Handling	$ 18.49	$ 22.22	$ 19.84
Prep & Feed	22.10	26.88	23.81
Gas Cleanup	92.50	89.25	77.68
Ash Handling	10.89	9.410	8.399
Balance of Plant	440.1	445.3	422.9
Total Plant	584.1	593.0	552.6

Exhibit 4-20
San Joaquin Valley and Four Corners IGCC Plants With CO_2 Capture
Total Capital Cost Estimates
(Million Current-Year Dollars)

Year	% of Total Capital Expenditure	San Joaquin Valley, CA IGCC	Four Corners, NM IGCC
2006	5.0 %	$ 33.67	$ 31.37
2007	20.0 %	136.9	127.6
2008	42.5 %	295.8	275.6
2009	32.5 %	223.0	214.3
Total	100.0 %	689.4	648.9

4.2.5 IGCC Plant Operating and Maintenance Costs

The operating and maintenance (O&M) costs are separated into two types, fixed and variable. The fixed O&M costs consist of administrative and support labor costs, those operating labor and maintenance costs that are the same each year regardless of the number of operating hours, and insurance and property taxes. The fixed O&M costs are estimated to be same for the plants with the exception of the insurance and property taxes, each of which are estimated based on 1% of the total capital cost. Variable O&M costs consist of consumables costs and those operating labor and maintenance costs that vary with the number of operating hours. Variable O&M costs other than fuel costs were adjusted from 1999 dollars to current-year dollars using the GEMSET IPD projection. Fuel costs were determined for each year based on the GEMSET baseline annual average fuel price projections. The fuel cost projections for the Pacific region of the U.S. were used for the San Joaquin Valley plant, and the projections for the Mountain region were used for the Four Corners, New Mexico, plant. The estimates of O&M costs for the San Joaquin Valley and Four Corners IGCC plants are compared to the baseline Case 3-E estimates in Exhibit 4-21 in fixed-year 1999 dollars. The O&M costs for IGCC plants located in the San Joaquin Valley and the Four Corners region of New Mexico in current-year dollars from 2010 through 2020 for plants beginning operation in 2010 are provided in Exhibit 4-22. 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%.

Exhibit 4-21
IGCC Plant With CO_2 Capture O&M Cost Estimates
(Fixed-Year 1999 dollars)

O&M Cost Category	Baseline Case 3-E	San Joaquin Valley, CA	Four Corners, NM
Fixed O&M Cost,$ Million/yr			
Operating	10.23	10.34	10.33
Admin & Support Labor	2.56	2.57	2.57
Insurance & Property	11.68	11.86	11.05
Total Fixed O&M Cost	24.47	24.78	23.95
Variable O&M Cost, $/MWh			
Variable O&M Excl. Fuel	3.22	4.62	5.24
Fuel Cost	11.95	14.00	9.39
Total Variable O&M Cost	15.17	18.62	14.63

Exhibit 4-22
San Joaquin Valley and Four Corners IGCC Plants With CO_2 Capture
O&M Cost Estimates (Current-Year Dollars)

Year	San Joaquin Valley, CA		Four Corners, NM	
	Fixed O&M (Million $)	Variable O&M ($/MW-hr)	Fixed O&M (Million $)	Variable O&M ($/MW-hr)
2010	30.05	20.59	29.05	15.60
2011	30.56	20.93	29.54	15.69
2012	31.06	21.28	30.03	15.72
2013	31.58	21.63	30.53	15.76
2014	32.11	21.93	31.04	15.84
2015	32.64	22.25	31.55	15.93
2016	33.19	22.62	32.08	16.07
2017	33.74	22.93	32.62	16.22
2018	34.30	23.26	33.16	16.29
2019	34.88	23.58	33.71	16.38
2020	35.46	23.91	34.27	16.52

4.2.6 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. The estimated performance characteristics are summarized in Exhibit 4-23, and the capital and O&M costs are summarized in Exhibit 4-24 and Exhibit 4-25. 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.

4.2.7 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.[19] An overview of the model's inputs and outputs, as well as its internally calculated values, is given in Exhibit 4-26.

The length of pipeline for transporting CO_2 from the Four Corners region of New Mexico to the San Joaquin Valley in California was estimated to be about 765 miles (1,230 km). A difference in elevation between the two locations of about 5,100 ft. was used based on the elevations of the Arizona Public Service Four Corners steam generating station near Farmington, New Mexico,[20] and the Lemoore NAS, California.[21] A pipeline entry CO_2 pressure of 2,200 psia was used, along with a minimum pressure criteria at any point in the pipeline of 1,215 psia to ensure that the CO_2 retains flow properties approximating a liquid. The MIT pipeline transport model was exercised to determine the diameter of pipe and number of compressor stations that would minimize the CO_2 transport cost. The model uses a unit cost of construction of $33,853/mile/inch of pipe diameter to calculate pipeline capital cost, based on construction cost for natural gas pipeline, and an annual pipeline O&M cost of $5,000/mile, both in fixed-year 1998 dollars. The results of the evaluation indicate that the minimum cost option is to size the pipeline to provide a pressure drop that would maintain the CO_2 above the 1,215 psia minimum until the end of the pipeline without recompression.

The location of the IGCC+S plant in the San Joaquin Valley, California, was assumed to be within 50 miles of the oil fields where the CO_2 would be used for EOR, based on the evaluation of oil fields in the region where CO_2 flooding would be economical. The pipeline entry CO_2 pressure, minimum pressure criteria, and unit costs of construction and maintenance used for this case were the same as used for the pipeline from New Mexico to the San Joaquin Valley.

The resulting pipeline designs and costs, in fixed-year 1998 dollars, are presented in Exhibit 4-27. The estimated capital and O&M costs adjusted to current-year dollars for a pipeline constructed over two years beginning in 2008 and operating from 2010 through 2020 are provided in Exhibit 4-28. These cost estimates were used in the financial analysis of the alternative cases discussed in Section 5.

Exhibit 4-23
IGCC Plant Without CO_2 Capture Performance Characteristics

	San Joaquin Valley, CA	Four Corners, NM
Coal	Wyodak PRB	Wyodak PRB
Turbo-Set Power Output, kW	474,029	393,444
Fuel Gas Expander Power, kW	0	0
Gross Power Output, kW	474,029	393,444
Coal Feed, MMBtu/h	3,343	2,775
Coal Feed, lb/hr	387,410	321,550
Ash/Slag Production, lb/h	22,470	18,650
Sulfur Production, lb/h	2,316	1,922
CO_2 Produced from Coal, lb/h	710,252	589,509
CO_2 Captured @ 90%, lb/h	0	0
CO_2 Emissions, lb/h	710,252	589,509
Auxiliary Power		
Coal Handling & Grinding, kW	1,430	1,190
Slag Handling & Dewatering, kW	120	100
Gas Cleanup, kW	2,890	2,420
HP CO_2 Compressor, kW (Note 1)	0	0
Balance of Auxiliary Power, kW	39,840	30,770
Total Auxiliary Power, kW	44,280	34,480
Net Power Output, kW	429,750	358,970
Heat Rate, Btu/kWh (% HHV)	7,780 (43.9)	7,730 (44.2)

Exhibit 4-24
IGCC Plant Without CO_2 Capture Capital Cost Estimates
(Million Current-Year Dollars)

Year	% of Total Capital Expenditure	San Joaquin Valley, CA IGCC	Four Corners, NM IGCC
2006	5.0 %	$ 26.79	$ 25.50
2007	20.0 %	108.9	103.7
2008	42.5 %	235.3	224.0
2009	32.5 %	183.0	174.2
total	100.0 %	$553.99	$527.40

Exhibit 4-25
IGCC Plant Without CO_2 Capture Unit O&M Cost Estimates
(Current-Year Dollars)

Year	San Joaquin Valley, CA		Four Corners, NM	
	Fixed O&M (Million $)	Variable O&M ($/MW-h)	Fixed O&M (Million $)	Variable O&M ($/MW-h)
2010	25.74	16.53	26.26	12.56
2011	26.17	16.80	26.70	12.64
2012	26.60	17.08	27.15	12.66
2013	27.05	17.37	27.60	12.69
2014	27.50	17.61	28.06	12.76
2015	27.96	17.86	28.53	12.83
2016	28.42	18.16	29.01	12.94
2017	28.90	18.41	29.49	13.06
2018	29.38	18.67	29.98	13.12
2019	29.87	18.92	30.48	13.19
2020	30.36	19.19	30.99	13.30

Exhibit 4-26
Overview of MIT Transport Model

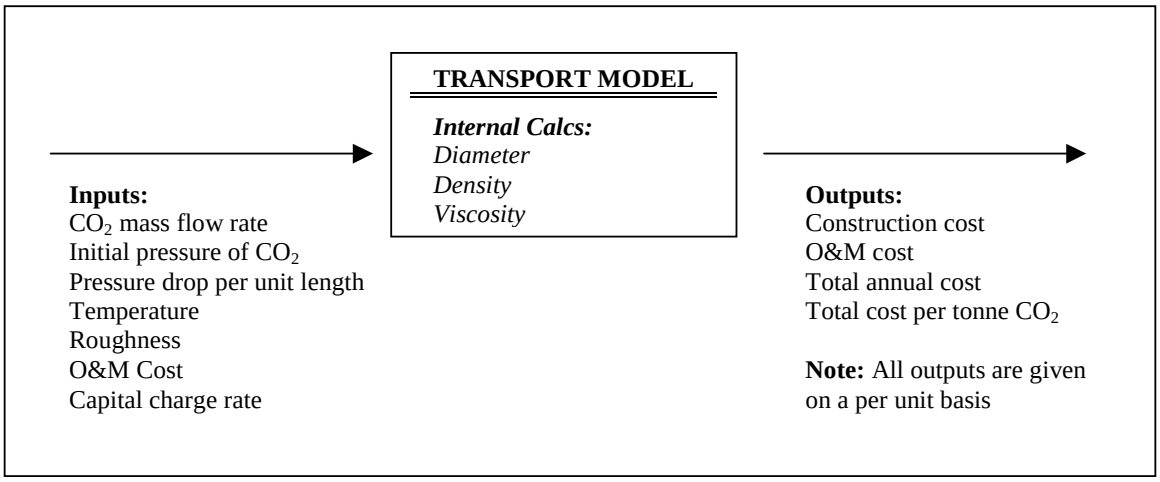


Exhibit 4-27
Pipeline Design Results

	Units	Four Corners, NM, to San Joaquin Valley, CA Pipeline	San Joaquin Valley Local Pipeline
CO_2 Flow Rate	tonne/day	6,439	7,758
Initial Pressure	psia	2,200	2,200
Outlet Pressure	psia	1,215	1,215
Pipe Length	miles	765	81
Pipe Diameter	inches	13.0	10.2
Nominal Pipe Size	inches	14	12
Pipeline Capital Cost	million dollars, 1998	$ 335.5	$ 17.29
Pipeline O&M Costs	million dollars/yr, 1998	$ 3.83	$ 0.25

Exhibit 4-28
Four Corners Region NM to San Joaquin Valley Pipeline Cost
(Current Year Dollars)

	Four Corners, NM, to San Joaquin Valley, CA Pipeline	San Joaquin Valley Local Pipeline
Capital Cost		
Year	**Million Dollars**	**Million Dollars**
2008	199.8	10.30
2009	203.2	10.47
Fixed O&M Costs		
Year	**Million Dollars**	**Million Dollars**
2010	4.71	0.308
2011	4.79	0.312
2012	4.87	0.319
2013	4.95	0.323
2014	5.03	0.329
2015	5.12	0.334
2016	5.20	0.340
2017	5.29	0.346
2018	5.38	0.351
2019	5.47	0.357
2020	5.56	0.363

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5. Coal-Based IGCC + CO_2 Sequestration Financial Analysis

California appears to be a good venue for consideration of IGCC+S: there is need for additional generating capacity, electric price is among the highest in the U.S., and there is an unserved market for CO_2 that could be used to conduct enhanced oil recovery that would pay for the sequestration equipment. Even though locating a coal-fueled power plant in California would be a daunting licensing problem, as the State of California environmental regulators have been long been averse to locating coal plants within their borders. However, we've made this plant exceptionally clean –equivalent to a natural gas combined cycle- so that siting such a plant should be possible. Doing that would be an incredible benchmark for the coal power industry.

However, a plant ultimately must be developed that has a sound financial prospect of acceptable return to its owner. This task used the GEMSET modeling system[22] to evaluate the financial merits of an IGCC+S plant compared to that of an NGCC under a series of economic scenarios. The discussion below shows the circumstances needed for the financial deployment of IGCC+S to serve the market conditions expected to exist for generators serving California.

5.1 Case Selection and Financial Assumptions

As discussed earlier in this Report, the intent of this analysis is to see whether an IGCC+S could be a viable alternative in the California market for electricity. In that regard, several cases were selected to demonstrate the financial robustness of such a technology. Given that siting a coal unit in California is indeed a daunting task, an alternative to siting in California was selected as an alternative for evaluation. It was decided that siting a unit in the Four Corners area of New Mexico, still providing the power to California, is a reasonable option for consideration. The CO_2 could be shipped to the oil fields in Texas and New Mexico from that site. Initially, it was considered that a pipeline could be built from Four Corners to the San Joaquin basin, but was ruled out after investigating the infeasibility of recovering the capital cost of building a pipeline over 700 miles long to serve the oil fields in that area.

In addition to the two sites, it was also deemed necessary to show the financial comparison of just building an IGCC plant without CO_2 sequestration in both sites. There is also a consideration of the two revenue streams that result from the sale of electricity from these units. As described earlier, 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, estimated 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 in the two sites under the competitive market price developed from the GEMSET program.

Finally, a case was structured that took the incremental costs associated with the CO_2 sequestration and enhanced oil recovery as a stand-alone situation. While somewhat speculative, it was believed that this would indicate the reasonableness of putting CO_2 capture on units of this nature in areas where enhanced oil recovery would assist the United States in increasing its oil supplies in an environmentally acceptable manner.

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 Texas 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 Texas 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 were discussed in previous sections of this Report and just 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 currently structured in PJM. (See Exhibit 5-1.) The total avoided cost pricing consists of the fuel component, O&M and fixed capital plus administration. For the scenario where 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 Characterization Database through 2024. (See Exhibit 5-1 for natural gas prices, and Exhibit 5-2 for all others)
- 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 based on the NPTO methodology using a factor based on the world price of oil, and transportation costs were based on a current tariff from a major pipeline company specializing in movements of CO_2. The formula used by NPTO is as follows: 0.5 + (.02*$/bbl of # 6 oil)

- 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.

In Exhibit 5-1 the pertinent electric prices and operating costs are summarized on an annual basis for the period of time of the bond financing. Exhibit 5-2 presents the coal and # 6 oil prices, and the CO_2 expected price used in the analysis.

Exhibit 5-1
Fuel, O&M, and Electric Pricing Estimates

Year	California Natural Gas Cost Current $	Fuel Cost $/kWh	Fixed (Capital) ($/kWh)	Variable O&M ($/kWh)	Administrative ($/kWh)	Avoided Cost Pricing COE ($/kWh)	Competitive Pricing San Joaquin COE ($/kWh)	Competitive Pricing Four Corners COE ($/kWh)
2010	$5.517	$0.038	$0.013	$0.005	$0.005	$0.061	$0.082	$0.076
2011	$5.697	$0.039	$0.013	$0.005	$0.005	$0.062	$0.084	$0.078
2012	$5.890	$0.041	$0.013	$0.005	$0.005	$0.064	$0.086	$0.080
2013	$6.087	$0.042	$0.013	$0.005	$0.005	$0.065	$0.088	$0.082
2014	$6.262	$0.043	$0.013	$0.005	$0.006	$0.067	$0.090	$0.084
2015	$6.418	$0.044	$0.013	$0.005	$0.006	$0.068	$0.092	$0.086
2016	$6.567	$0.045	$0.013	$0.005	$0.006	$0.069	$0.095	$0.088
2017	$6.703	$0.046	$0.013	$0.005	$0.006	$0.070	$0.097	$0.090
2018	$6.862	$0.047	$0.013	$0.005	$0.006	$0.072	$0.099	$0.092
2019	$7.029	$0.048	$0.013	$0.005	$0.006	$0.073	$0.101	$0.094
2020	$7.214	$0.050	$0.013	$0.006	$0.006	$0.074	$0.103	$0.096
2021	$7.345	$0.051	$0.013	$0.006	$0.006	$0.076	$0.106	$0.098
2022	$7.479	$0.052	$0.013	$0.006	$0.006	$0.077	$0.108	$0.100
2023	$7.615	$0.053	$0.014	$0.006	$0.007	$0.079	$0.110	$0.103
2024	$7.753	$0.053	$0.014	$0.006	$0.007	$0.080	$0.113	$0.105

Exhibit 5-2
Annual Fuel and CO_2 Prices (Current $)

Year	California Region 9 Coal $/10^6 Btu	Four Corners Region 8 Coal $/10^6 Btu	# 6 Oil $/10^6 Btu	CO_2 $/10^3 scf
2002	1.393	1.002	4.510	1.055
2003	1.445	1.018	4.772	1.087
2004	1.469	1.020	5.005	1.115
2005	1.477	1.015	5.072	1.124
2006	1.487	0.993	5.083	1.125
2007	1.507	0.978	5.269	1.148
2008	1.526	0.978	5.536	1.181
2009	1.541	0.976	5.910	1.227
2010	1.561	0.970	6.296	1.274
2011	1.587	0.969	6.519	1.302
2012	1.614	0.960	6.693	1.323
2013	1.641	0.953	6.838	1.341
2014	1.662	0.950	6.919	1.351
2015	1.684	0.947	7.073	1.370
2016	1.712	0.950	7.272	1.394
2017	1.734	0.953	7.423	1.413
2018	1.757	0.948	7.577	1.432
2019	1.779	0.945	7.734	1.451
2020	1.803	0.947	7.893	1.471
2021	1.827	0.949	8.055	1.491
2022	1.851	0.951	8.219	1.511
2023	1.876	0.953	8.386	1.531
2024	1.901	0.955	8.554	1.552

5.2 Financial Spreadsheets and Results

All of the seven cases were evaluated using a financial model developed for use by 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, there is included in the Appendix, attached to this Report, the following:

- 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;

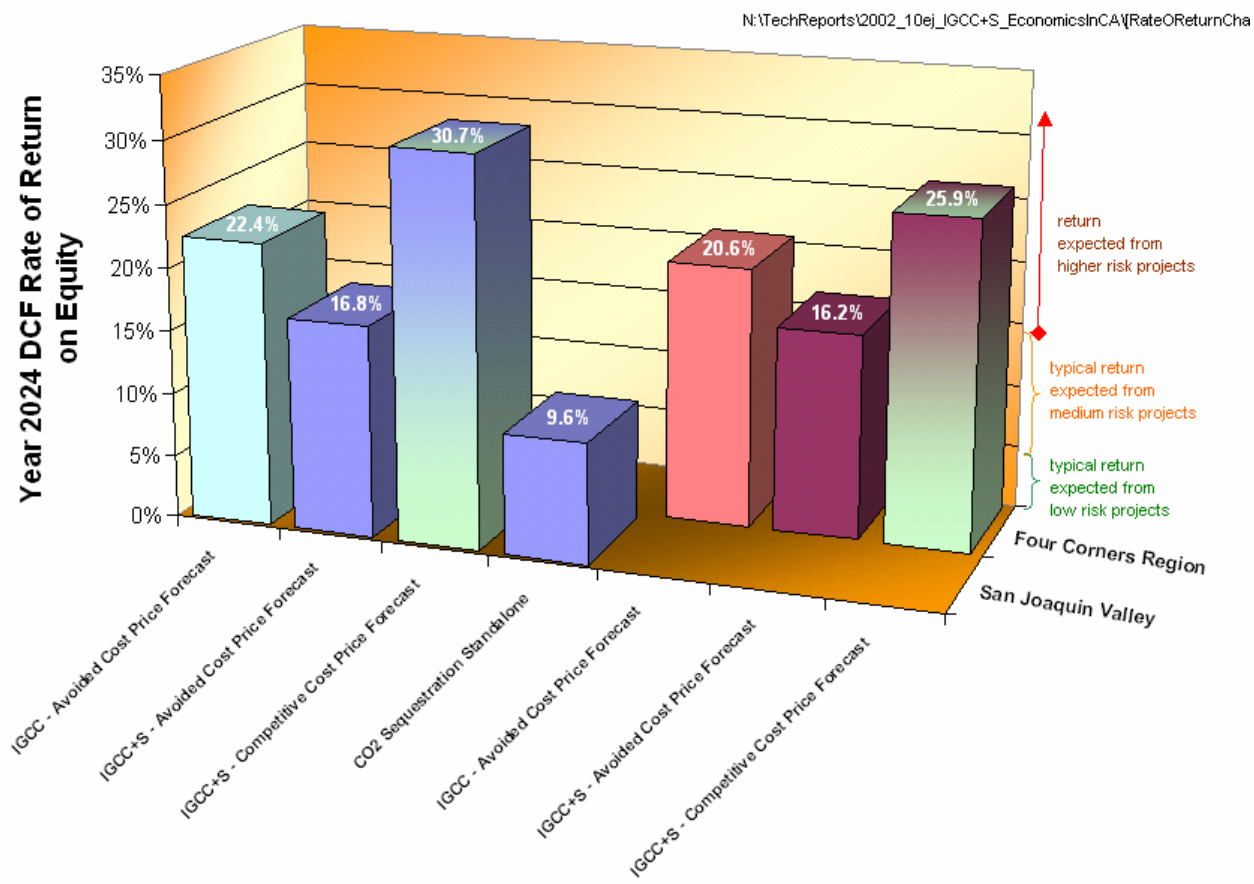
- A Balance Sheet, and finally

- A calculation of the project's return on Equity.

It is the Return on Equity that demonstrates the robustness of the project for the financing community. Exhibit 5-3 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 DCF basis indicate that the projects are overwhelmingly financially viable. The details behind each of these calculations are provided in the Appendix attached.

Exhibit 5-3
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%



5.2.1 Graphical Summary of Results

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

Exhibit 5-4
Case A – IGCC+S San Joaquin Valley (Avoided Cost Pricing)

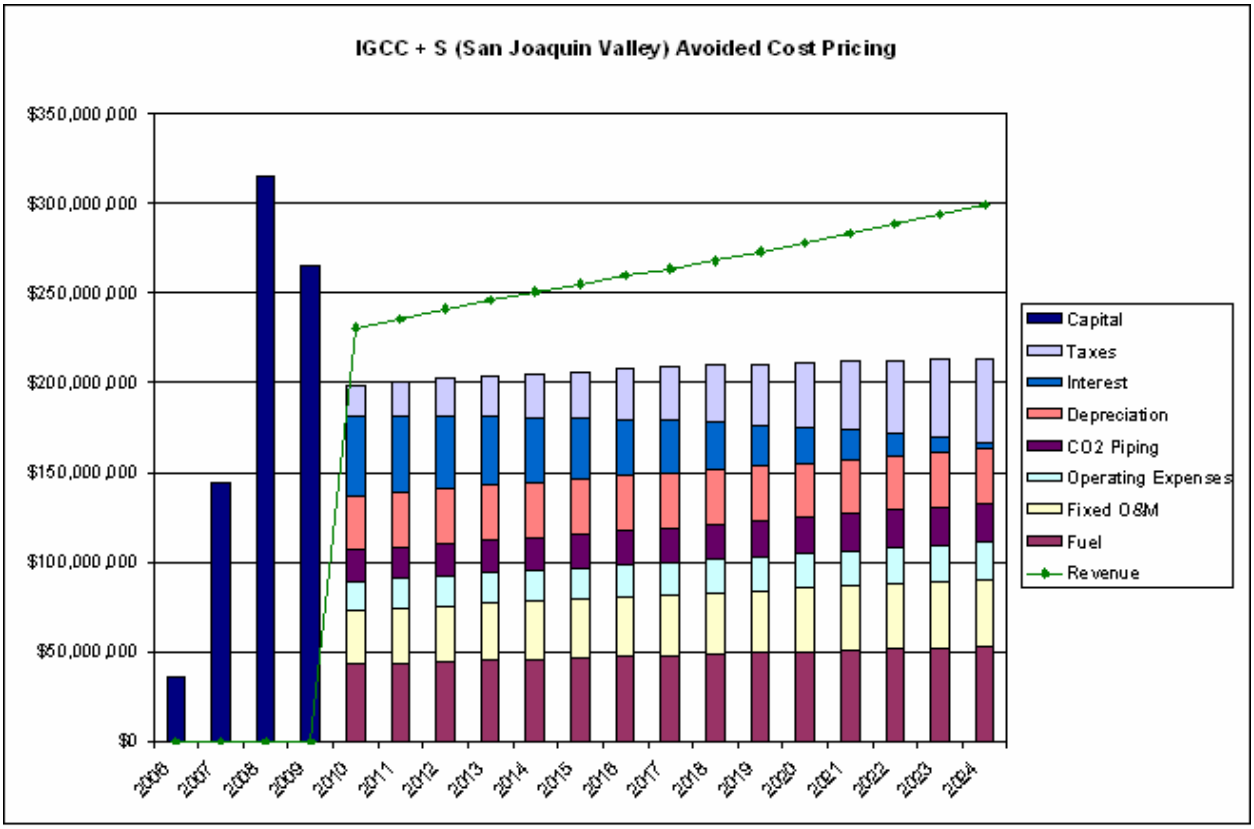


Exhibit 5-5
Case B – IGCC San Joaquin Valley (Avoided Cost Pricing)

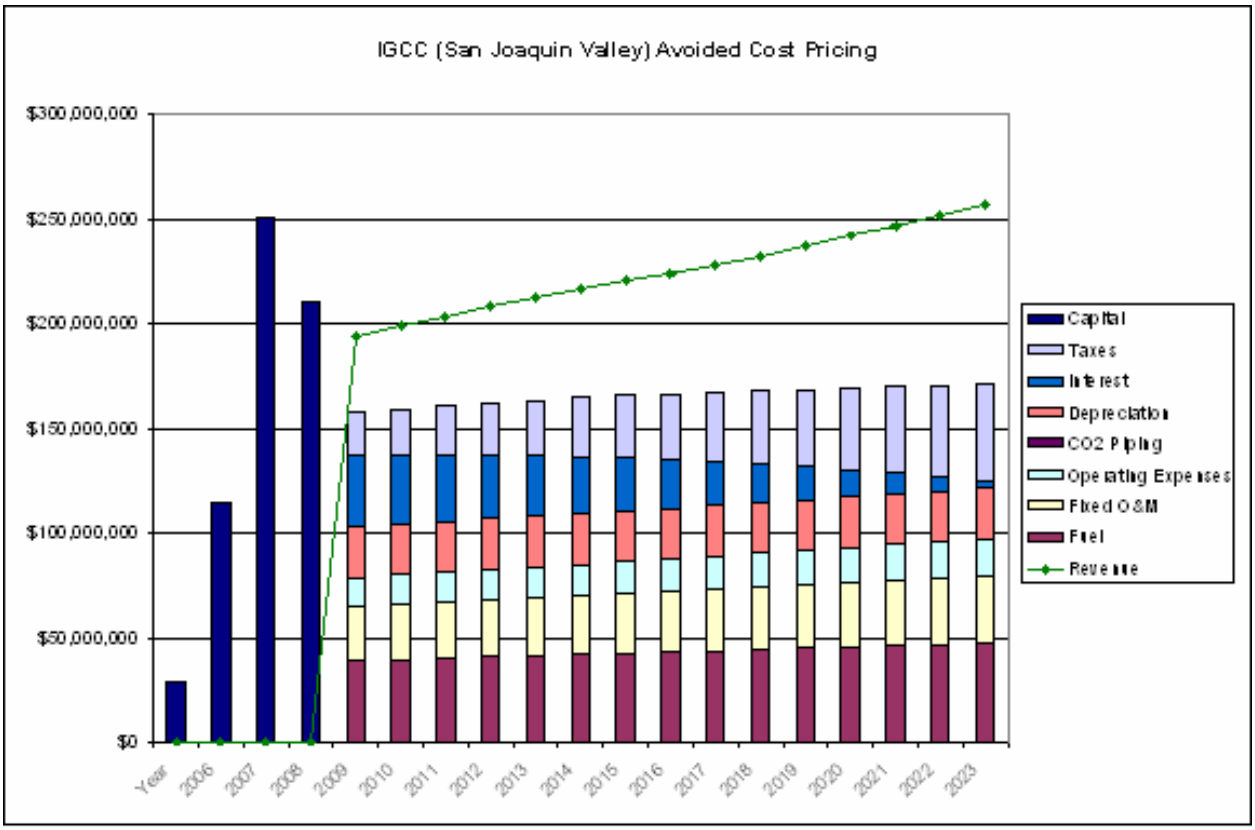


Exhibit 5-6
Case C – IGCC+S San Joaquin Valley (Competitive Pricing)

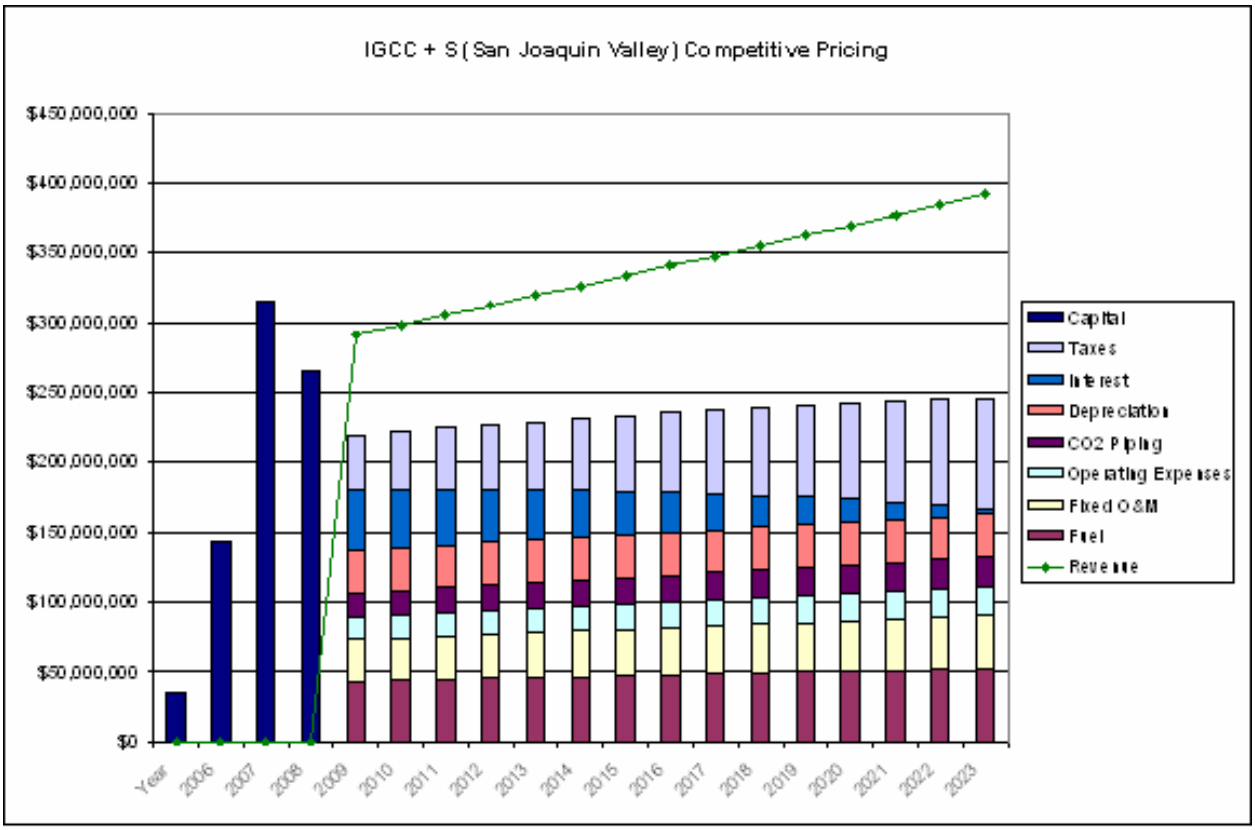


Exhibit 5-7
Case D – IGCC+S Four Corners Region (Avoided Cost Pricing)

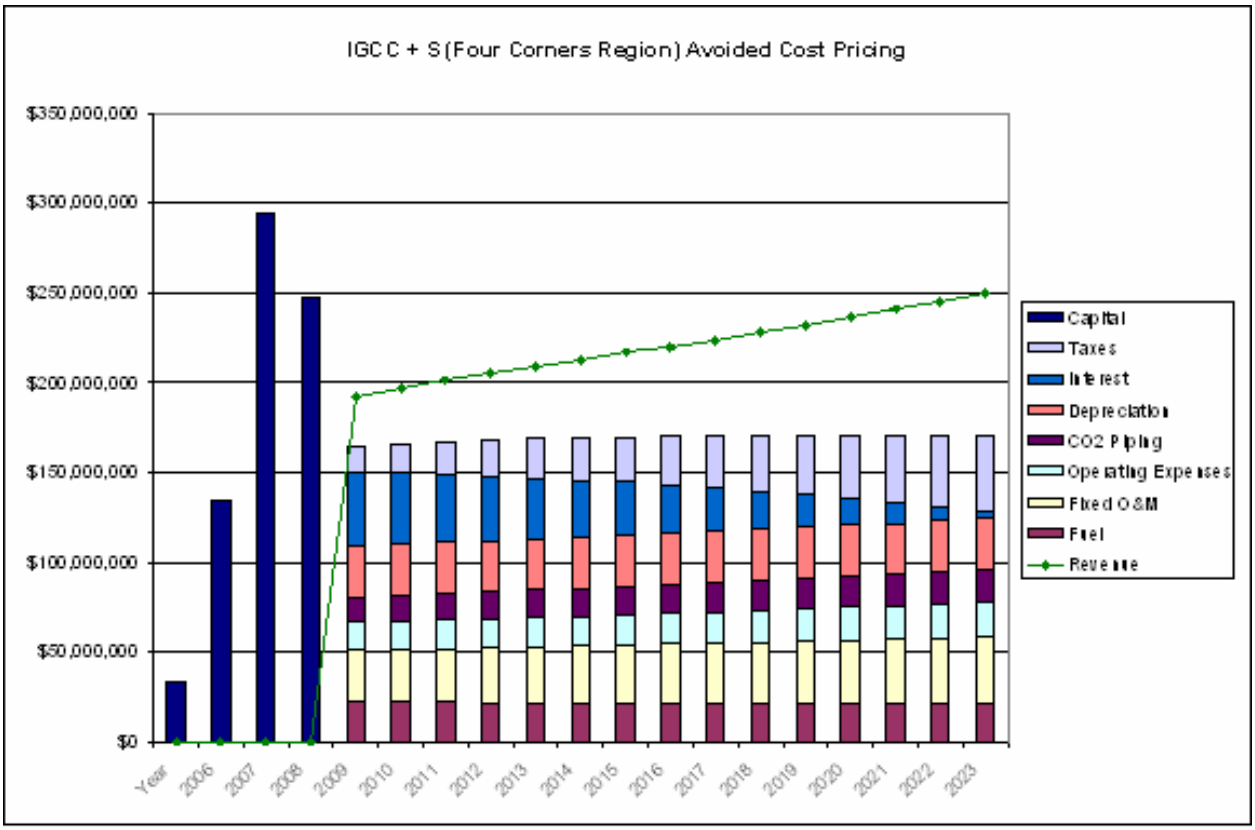


Exhibit 5-8
Case E – IGCC Four Corners Region (Avoided Cost Pricing)

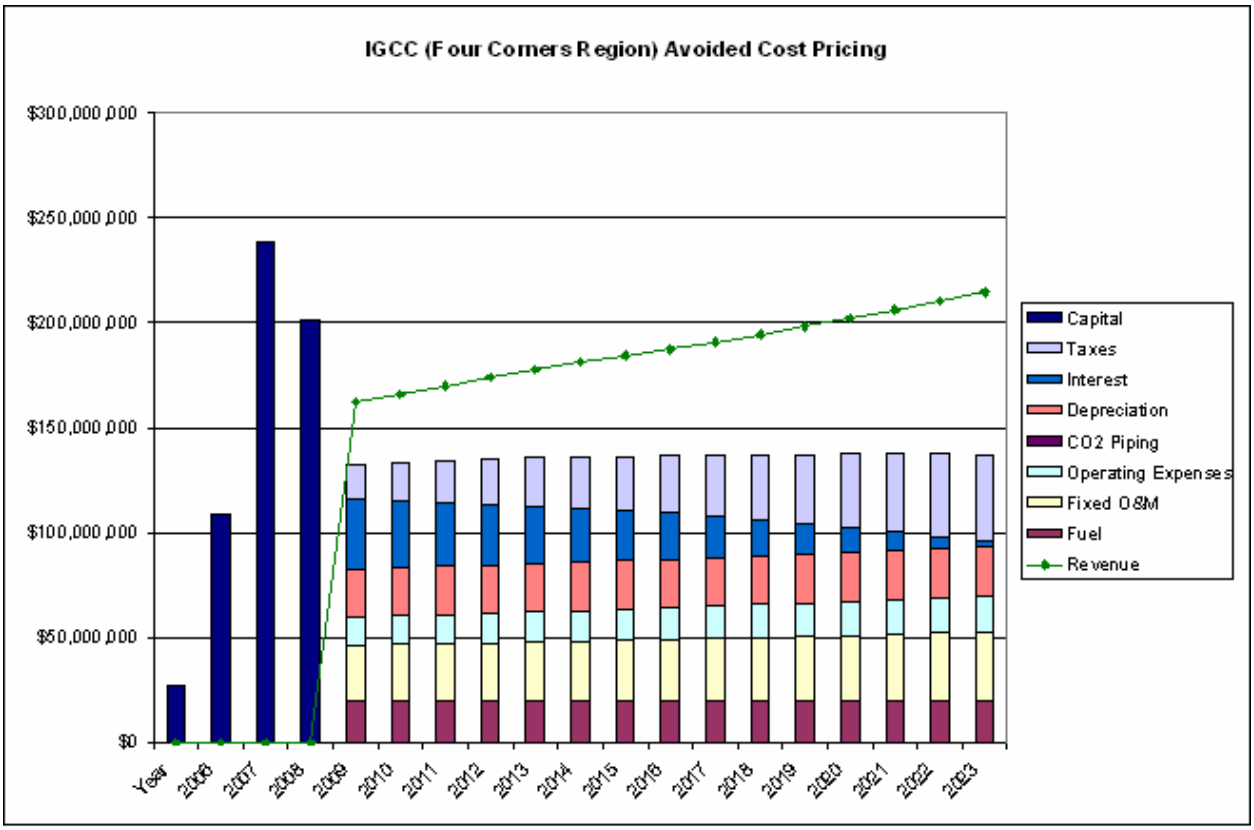


Exhibit 5-9
Case F – IGCC+S Four Corners Region (Competitive Pricing)

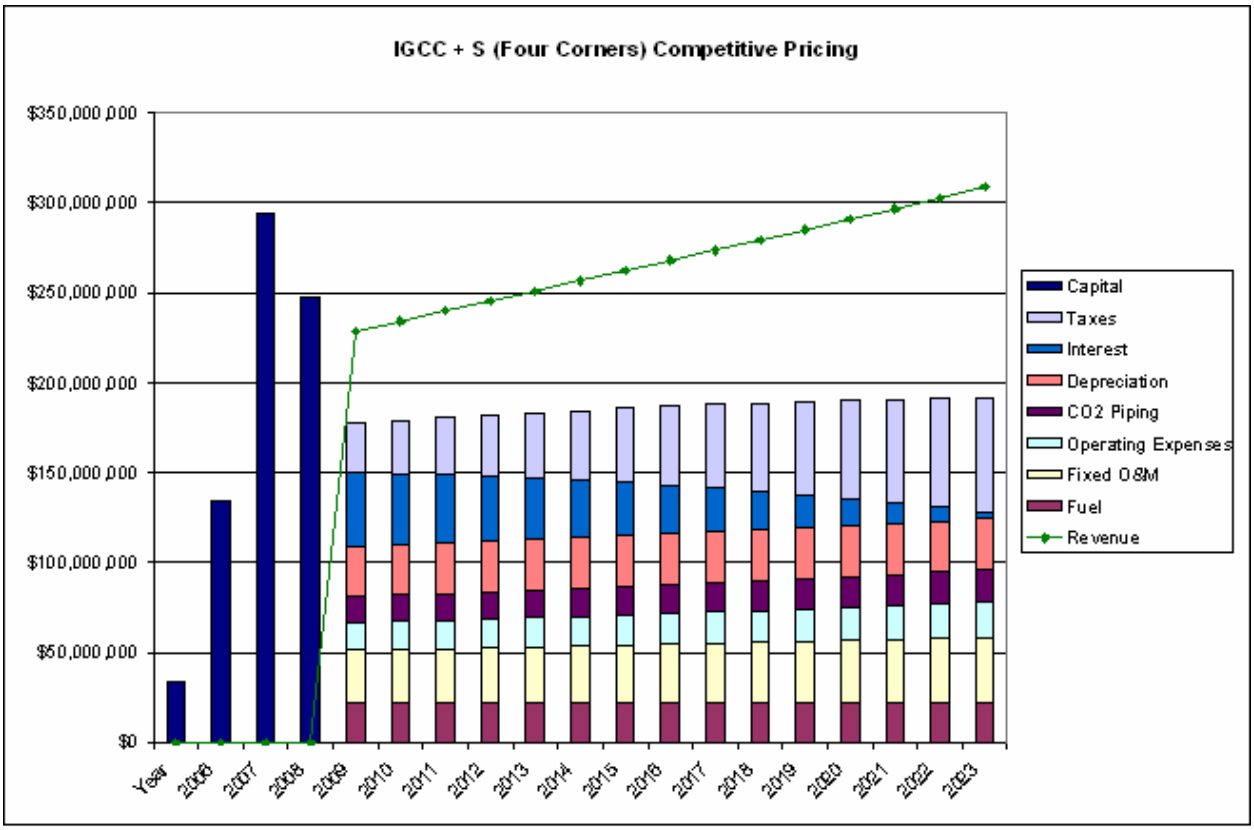
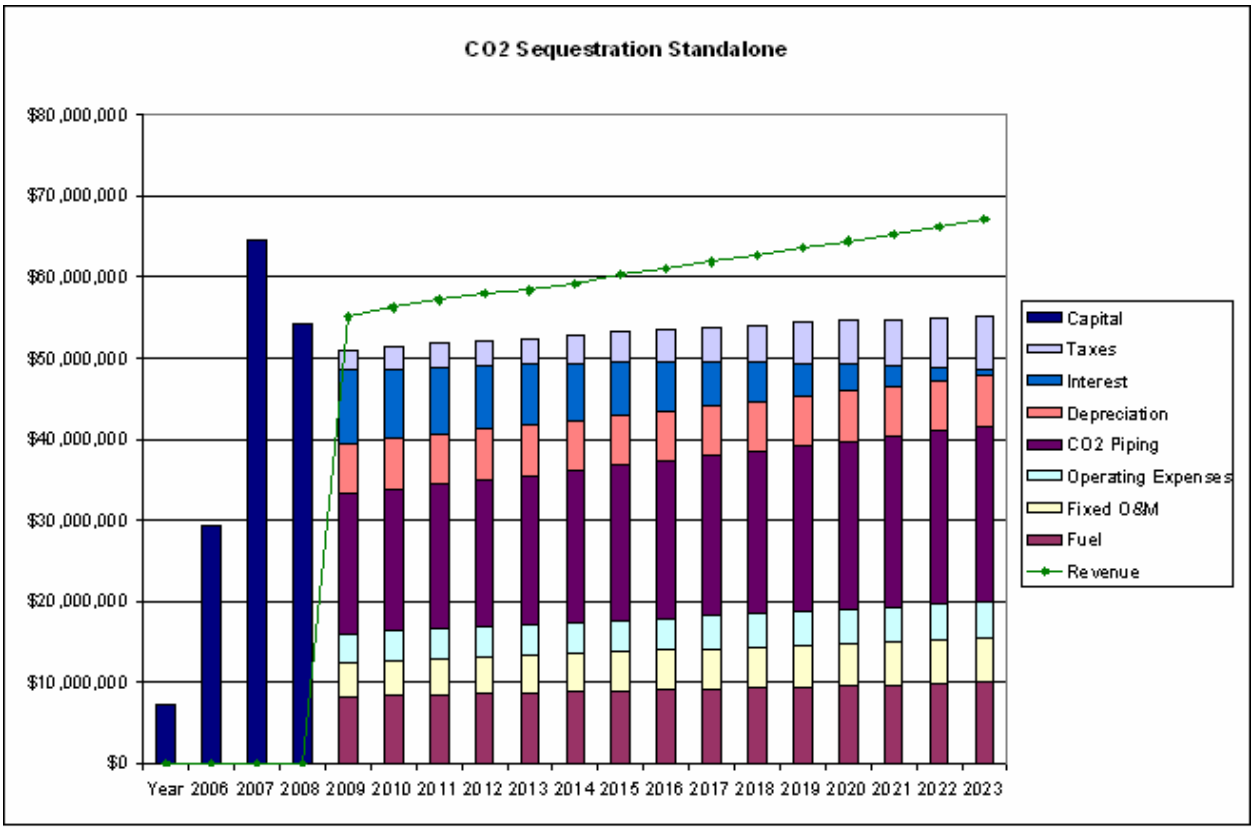


Exhibit 5-10
Case G – CO_2 Sequestration Standalone



6. References

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[16] 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. 23.

[17] 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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